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of Transportation

**Research and
Special Programs
Administration**

Annual Report on Pipeline Safety

Materials
Transportation
Bureau

Calendar Year 1980

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ANNUAL REPORT ON PIPELINE SAFETY

PIPELINE SAFETY ACT
(PUBLIC LAW 96-129)

Calendar Year 1980

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16. Abstract

This report is a summary of DOT activity associated with the administration of the Pipeline Safety Act of 1979 for calendar year 1980. The report includes the year's highlights, and detailed coverage of gas and liquid pipeline failures and casualties, regulatory activity, compliance activity, federal/state cooperation and the grant-in-aid program, research studies, dissemination of pipeline safety information, a summary of outstnading problems, a lisitng of waivers granted under the act, and a report of activity related to the construction of the Alaska Natural Gas Transportation System.

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FOREWORD

This report of the Department of Transportation's (DOT) program to further pipeline safety includes two elements: the annual report on the administration of the Natural Gas Pipeline Safety Act and the annual report on the administration of the Hazardous Liquid Pipeline Safety Act. The information presented covers the Department's pipeline activities for calendar year 1980.

Natural Gas Pipeline Safety

The report on the administration of the Natural Gas Pipeline Safety Act (NGPSA) of 1968, as amended, (49 USC 1671 et seq.) is submitted in accordance with section 16 of the Act.

The NGPSA provides for Federal safety regulation of those facilities used in the transportation by pipeline of natural and other gases in or affecting interstate or foreign commerce.

DOT's responsibility for safety regulation of natural gas pipelines involves more than 2,300 operators of a gas pipeline network of more than 1.5 million miles. The total includes almost 25,000 miles of gathering lines, 267,000 miles of transmission pipelines, 800,000 miles of distribution mains, and 480,000 miles of gas service lines. This translates into a total number of 42,500,000 gas services. DOT is also responsible for regulating approximately 81,000 master meter operators. DOT regulatory programs are designed to assure safety in the design, siting, construction, testing, operation, and maintenance of gas systems.

Liquid Pipeline Safety

The Hazardous Liquid Pipeline Safety Act of 1979 (Title II of P.L. 96-129; 93 Stat. 1003) granted DOT substantial new regulatory and enforcement authority over liquid pipelines which mirrors that granted by the NGPSA. Specific provisions allow for:

(1) establishment of minimum Federal safety standards governing the transportation of hazardous liquids by pipeline;
(2) a program for Federal/state cooperation in regulating intrastate liquid pipelines and Federal financial assistance to state agencies; and
(3) establishment of civil penalties for violations of the Federal standards.

Departmental Responsibilities

The Department's pipeline safety program is administered by the Materials Transportation Bureau (MTB) of the Research and Special Programs Administration.

Pipeline safety functions delegated to the Bureau include developing, approving, issuing, and enforcing regulations for the safe transportation of gases and hazardous liquids by pipeline; managing Federal grants to aid states in conducting intrastate pipeline safety programs; collecting, compiling, and analyzing pipeline safety and operating data; conducting training programs for government and industry personnel; and operating, coordinating and maintaining an emergency response program for state and local jurisdictions dealing with pipeline accidents.

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* Contains information relating to both gas and liquid pipeline safety programs

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FEDERAL GAS PIPELINE SAFETY STANDARDS

Notices of Proposed Rulemaking

In 1980, eight Notices of Proposed Rulemaking were issued to amend the gas pipeline safety regulations contained in 49 CFR, Part 192.

Liquefied Natural Gas Facilities: Federal Safety Standards (45 FR 9220). On January 30, 1980, MTB proposed establishment of a set of comprehensive safety standards governing operations (including security), maintenance, fire protection and corrosion control in liquefied natural gas (LNG) facilities used in the transportation of natural gas by pipeline in or affecting interstate or foreign commerce. The new standards would provide safety primarily through development and implementation of written procedures, personnel training, and standardized tests and inspections.

Transportation of Natural and Other Gas by Pipeline; Transportation of Hazardous Liquids by Pipeline; Qualification of Metallic Components (45 FR 13783). On February 26, 1980, MTB proposed criteria to qualify for use under Parts 192 and 195 metallic pipeline components manufactured according to editions of documents incorporated by reference that: (1) are not listed as applicable editions to those referenced documents and (2) predate the earliest applicable effective dates of Parts 192 and 195.

The new criteria would apply to gas pipeline facilities as defined in Part 192, and to interstate and intrastate pipeline facilities used in the transportation of hazardous liquids as those terms are defined in the Hazardous Liquid Pipeline Safety Act of 1979 (Title II of P.L. 96-129. November 30, 1979).

Transportation of Natural and Other Gas and Hazardous Liquids by Pipeline; Incorporation by Reference (45 FR 16226). On March 4, 1980, MTB proposed to amend Parts 192 and 195 to update the existing references to documents prepared by industry so as to reflect later published editions of those documents.

Transportation of Natural and Other Gas by Pipeline, Transportation of Liquids by Pipeline, Placing Longitudinal Weld Seams in Upper Half of Pipe (45 FR 20142). On March 19, 1980, MTB requested comments on a recommendation by the National Transportation Safety Board (NTSB) to locate longitudinal weld seams in the upper half of the pipe as a means to reduce the potential for pipeline failures caused by corrosion in the longitudinal weld seams.

Transportation of Natural and Other Gas by Pipeline; Interior Piping (45 FR 22118). On March 26, 1980, MTB requested comments relative to the need for Federal safety regulation of gas piping located inside buildings, whether these buildings be classified as commercial, industrial, a domicile, or place of congregation such as auditoriums, churches, or schools. Interior piping upstream from gas meters is currently subject to Federal or state regulatory authority, as well as local building codes, and compliance with Federal requirements may be inappropriate.

Amendments to the Regulations

Four amendments were made to the Federal gas pipeline safety standards (49 CFR Part 192) during the year.

Repair of Transmission Line. Effective January 17, 1980, the regulations covering general requirements for repair procedures of gas pipelines were amended by correcting a reference to another regulation.

Joining of Plastic Pipe. Effective July, 1, 1980, MTB made certain changes in response to comments on a final rule published July 23, 1979, establishing tests for qualifying procedures and personnel to make all types of joints in plastic pipeline used in the transportation of natural and other gas by pipeline (see Appendix A).

The most significant changes: (1) permit the use of any force on a specimen lateral joint that initiates failure; (2) permit tensile testing at ambient temperature and humidity; (3) more clearly define the criteria for test specimen acceptance or failure; (4) permit joining of pipe and fittings manufactured before July 1, 1980, in accordance with existing procedures without requalifying those procedures; (5) permit alternative test methods for qualifying persons to make heat fusion, solvent cement, or adhesive joints; and (6) redefine and limit the conditions under which a person must requalify to make plastic pipe joints.

Separately Protected Service Line. Effective April 7, 1980, the regulations which established requirements for testing, on a sampling basis, cathodic protection on short sections of transmission lines were amended to reinstate the original requirement which allowed separately protected service lines, regardless of their length, to be tested on a sampling basis if annual tests are impractical (see Appendix A).

Liquefied Natural Gas Facilities. Regulations which established new safety standards governing the operations, maintenance (including corrosion control), fire protection,

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personnel qualifications and training, and security of liquefied natural gas facilities used in the transportation of gas by pipeline in or affecting interstate or foreign commerce were issued. The previous regulations were considered inadequate because they did not provide an acceptable level of safety.

In Part 193, the amendments to §§ 193.2304 and 193.2431(c) became effective on November 24, 1980. The rules for operations maintenance, personnel qualifications and training, fire protection, and security (including § 193.2017) became effective July 23, 1980, except that the following sections, which may require a longer period for the purchase and installation of new equipment or material, do not become effective until January 1, 1982: §§ 193.2511, 193.2519, 193.2817, 193.2819, 193.2821, 193.2905, 193.2907, 193.2909, 193.2911 and 193.2915 (see Appendix A).

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WAIVERS REQUESTED UNDER THE ACT

The Department granted three waivers from compliance with the Federal gas pipeline safety standards in 1980.

Tennessee Gas Pipeline Company

The Tennessee Gas Pipeline Company petitioned for a waiver from compliance with the applicable line marking requirements of § 192.707 of the Federal gas pipeline safety standards (49 CFR Part 192) for their pipeline systems 100 and 800 which cross the Mississippi River near Greenville, Mississippi, and Lake Providence, Louisiana, respectively, in a catenary or curved configuration.

In lieu of placing a line marker at each crossing of the river, as required by § 192.707(a) (1), the petitioner requested that it be allowed to use a marking method that would delineate a zone, or corridor, containing all the pipeline crossings in that zone.

MTB found that compliance with § 192.707 was unnecessary and that the requested waiver would not be inconsistent with pipeline safety. The waiver of compliance was effective April 4, 1980.

Champlin Petroleum Company

The Champlin Petroleum Company petitioned for a waiver from compliance with the cathodic protection requirements of Subpart I of 49 CFR Part 192. The petition stated that the gas gathering lines for which the waiver was requested operate at a vacuum to remove the gas from the crude oil at the wellhead. Also, the gas gathering lines are continuously monitored for air content to permit early detection of any leak in the gas gathering pipelines, and all detected leaks are promptly repaired.

MTB found that compliance with Subpart I, 49 CFR Part 192, is unnecessary under the circumstances set forth in the petition and that the requested waiver would not be inconsistent with pipeline safety. The waiver of compliance was effective December 18, 1980.

Columbia Gas Transmission Corporation

The Columbia Gas Transmission Corporation petitioned for a waiver from compliance with the applicable requirements of § 192.327(e) of the Federal gas pipeline safety standards (49 CFR Part 192) for their transmission line, MA, at its crossing of the Susquehanna River, two miles above the Conowingo Dam in Harford and Cecil Counties, Maryland.

The petitioner is replacing five 10-inch pipelines crossing the Susquehanna River with one 20-inch pipeline. The existing pipelines were laid on the river bottom without cover. The petition requested that a waiver be granted to permit the replacement line to be laid in the same manner as the existing line.

MTB found that compliance with § 192.327(e) is unnecessary and that the requested waiver would not be inconsistent with pipeline safety. The waiver of compliance was effective December 19, 1980.

State-Granted Waiver

Under Section 3(e) of the NGPSA, the Department sanctioned a waiver granted by the Tennessee Public Service Commission to the Memphis Light, Gas and Water Division. The requested waiver is to permit installation of Driscopipe 8000 in a high-pressure system in a new residential development in southeast Shelby County, with design pressure based on a long-term hydrostatic strength of 1600 psi as recommended by the Plastic Pipe Institute. The section of the Federal regulations to which the waiver applies is 192.121.

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FEDERAL-STATE COOPERATION AND GRANT-IN-AID PROGRAM

In 1980, 52 of 53 state jurisdictions (including the District of Columbia, Puerto Rico, and two agencies in Florida) participated in the Federal gas pipeline safety program with respect to part or all of their intrastate facilities. Alaska did not participate in the program.

Section 5(a) Certification

Under section 5 of the NGPSA, states may participate in the Federal gas pipeline safety program by filing a certification under section 5(a) or by entering into an agreement under section 5(b). States certified under section 5(a) assume regulatory and enforcement authority over intrastate gas facilities. To qualify, a state must have adopted gas pipeline regulations at least as stringent as the Federal standards and must provide for enforcement authority for those standards by injunctive and monetary sanctions substantially the same as those authorized by sections 11 and 12 of the NGPSA. In 1980, the following 48 state jurisdictions participated in the Federal gas pipeline safety program under section 5(a) certification:

Alabama
Arizona
Arkansas
California
Colorado
Connecticut
District of Columbia
Florida PSC
Florida State Treasurer (LP Gas Div)
Georgia
Hawaii
Idaho
Illinois
Indiana
Iowa
Kansas
Kentucky
Louisiana
Maine
Maryland
Michigan
Minnesota
Mississippi
Missouri
Montana
Nevada
New Hampshire
New Mexico
New York
North Carolina
North Dakota
Ohio
Oklahoma
Oregon
Pennsylvania
Rhode Island
South Carolina
South Dakota (withdrew June 1980)
Tennesse
Texas
Utah
Vermont
Virginia
Washington
West Virginia
Wisconsin
Wyoming
Puerto Rico

Section 5(b) Agreements

State agencies that do not meet the criteria for a 5(a) certification may enter into a 5(b) agreement to undertake certain aspects of a gas pipeline safety program for intrastate facilities on behalf of the Department. Under a section 5(b) agreement, a state agency will conduct surveillance of the operator to ascertain compliance with Federal standards. Any probable violations are reported to DOT for Federal enforcement action. In 1980, four states held 5(b) agreements—Delaware, Massachusetts, Nebraska, and New Jersey.

Grants-In-Aid Program

In 1980, 48 states applied for financial assistance and were allotted funds as shown in Table 1.

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Table 1

ALLOCATION OF FY 1980 FEDERAL FINANCIAL ASSISTANCE FUNDS FOR GAS PIPELINE SAFETY PROGRAMS

State	Amount of Federal Funds
Alabama	167,210.00
Arizona	25,130.00
Arkansas	54,268.50
California	156,151.00
Colorado	48,534.00
Connecticut	42,800.00
Delaware	10,431.50
Florida (State Treasurer—LP Gas Div.)	42,532.50
Georgia	83,950.00
Hawaii	12,500.00
Idaho	16,058.50
Illinois	143,580.00
Indiana	60,635.50
Iowa	38,523.00
Kansas	50,505.00
Kentucky	148,307.00
Louisiana	249,506.50
Maine	13,305.00
Maryland	32,580.05
Massachusetts	45,829.14
Michigan	137,920.00
Minnesota	53,273.00
Mississippi	86,461.50
Missouri	79,068.50
Montana	19,572.50
Nebraska	47,167.50
Nevada	23,005.00
New Hampshire	20,404.00
New Jersey	96,731.50
New York	592,335.00
North Carolina	83,725.00
North Dakota	12,920.00
Ohio	106,150.00
Oklahoma	51,211.00
Oregon	52,676.00
Pennsylvania	117,959.70
Rhode Island	64,359.00
South Dakota	19,517.50
Tennessee	123,647.00
Utah	24,700.00
Vermont	18,425.00
Virginia	41,972.50
Washington	56,360.50
West Virginia	81,800.00
Wisconsin	79,105.00
Wyoming	84,450.50
District of Columbia	37,750.00
Puerto Rico	21,095.00
TOTAL	**$3,674,129.39**

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ENFORCEMENT ACTIVITY

Direction of Compliance Efforts

MTB directed its enforcement program to the following principal areas to assure that gas pipeline operators met the requirements of the Federal gas pipeline safety regulations during 1980:

- Monitoring the gas pipeline safety program of state regulatory agencies cooperating with MTB under the NGPSA to assure the adequate performance of state agencies;
- Inspecting and monitoring intrastate gas pipeline systems under direct MTB jurisdiction (those not subject to regulation by a cooperating state agency) to assure that such operators comply with Federal pipeline safety regulations;
- Inspecting interstate gas pipeline systems and monitor ing state agencies acting for MTB with regard to inspection of interstate gas operators to assure compliance; and
- Investigating pipeline failure incidents to determine whether violations of Federal standards occurred or if revisions or additions to regulations are needed.

MTB maintains five regional offices—in Washington, D.C.; Atlanta, Georgia; Kansas City, Missouri; Houston, Texas; and Burlingame, California. (See map on following page.)

MTB Field Monitoring of State Programs

Each regional office monitors the gas pipeline safety programs being conducted by state agencies in its region to assure that each state agency is conducting a program in consonance with its certification or agreement. Forty-seven jurisdictions certified under section 5(a) of the NGPSA and all four jurisdictions having agreements under section 5(b) were evaluated by MTB field personnel in 1980. South Dakota withdrew from its 5(a) participation before an evaluation had been performed.

MTB and State Inspection Programs

Each regional office also performs inspections of interstate and intrastate gas pipeline systems under direct Federal jurisdiction to determine the degree of compliance with the Federal safety standards. The majority of these systems are interstate gas transmission and municipally-owned gas distribution systems that are not under a state's safety regulatory authority. The remainder are master meter operators or intrastate gas transmission operations.

During the year, MTB inspected 161 intrastate systems and 77 interstate systems expending a total of 475 person-days. State agencies inspected 3,603 gas pipeline operators under their direct jurisdiction, expending a total of 17,324 person-days. (Detailed information relating to state inspection activity and personnel involved appears in the accompanying tables.)

MTB Enforcement Activity

An operator of a gas pipeline system subject to Federal pipeline safety regulation is subject to an enforcement action if that operator violates a Federal safety regulation. When a civil penalty is assessed, the amount of the penalty may be compromised based on criteria established in the NGPSA: the nature, circumstances, and gravity of the violation; the degree of culpability of the operator; any history of prior violation by the operator; the effect of the penalty on the operator's ability to continue to do business; the operators ability to pay the penalty; and the good faith of the operator in attempting to comply with the regulations. If a penalty is determined to be inappropriate, a compliance order is issued to the operator requiring specific actions to bring the pipeline system into compliance with the regulations. When the nature of the violation warrants a less stringent compliance action, a warning letter is sent to the operator. A hazardous facility order is issued to effect immediate corrective action in situations of public hazard.

During 1980, enforcement actions were initiated against 96 gas pipeline operators who were in violation of the Federal safety regulations. Forty-nine actions involving the preliminary assessment of a civil penalty, the issuance of a proposed compliance order, or both, were initiated. One action was initiated by issuing a hazardous facility order. After considering arguments and information submitted by the Regional personnel and the operator in writing or in informal hearings, the Associate Director for Operations and Enforcement assessed 29 civil penalties amounting to $60,500 and issued 21 compliance orders. Regional Chiefs sent a total of 47 warning letters.

Thirty-five operators paid a total of $56,300 in compromise of civil penalties assessed for violations of the Federal standards. (See Appendix C) Sixty-three cases remained active at the end of 1980. A national enforcement profile appears in the following table.

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MATERIALS TRANSPORTATION BUREAU REGIONAL BOUNDARIES

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Table 2

Profile of National Surveillance and Enforcement of Gas Gas Pipeline Systems 1980

		MTB	State Agencies	Total
Days Utilized in Performing Inspections		475	17,324	17,799
Enforcement Actions Initiated		49	1,497	1,546
Civil Penalty Assessments Made	No.	29	6	35
	Amt.	$60,500	$6,811,000	$6,871,500
Civil Penalties Collected	No.	35	5	40
	Amt.	$55,300	$ 2,200	$ 57,500
Enforcement Actions Closed Without Penalty		78	(Not Available)	

Table 3

1980 State Agency Inspection Activity

STATE	Gas Operators Inspected	Inspections Made (In Person-days)	Noncompliances Found	Noncompliances Corrected In 1980 *Includes Corr. From 1979	Noncompliance To Be Checked In 1980 *Includes Corr. From 1979	Noncompliances Submitted for DOT Action	Enforcement Actions Taken	Penalties Assessed	Penalties Collected
*Interstate Agent Activities Included									
Alabama	269	529	262	153	109	0	122	0	0
Arizona	11	31	21	11	10	0	5	0	0
Arkansas	58	407	277	272	5	0	0	0	0
California	6	345	148	80	68	0	0	0	0
Colorado	23	248	74	39	35	0	25	0	0
Connecticut*	12	119	38	17	21	0	0	0	0
Delaware	3	80	2	1	1	2	0	0	0
Florida PSC*	130	687	187	97	90	0	2	2: 10,000	2: 2,000
Florida OT	101	238	265	187	78	0	5	1: 200	1: 200
Georgia	90	289	178	120	58	0	96	0	0
Hawaii	1	178	0	0	0	0	0	0	0
Idaho	2	135	2	2	0	0	0	0	0
Illinois	146	787	48	50*	1	0	48	0	0
Indiana	102	235	35	39*	5	0	15	0	0
Iowa*	35	150	57	74	123*	0	5	0	0
Kansas	43	152	44	48*	0	0	0	0	0
Kentucky*	17	172	69	43	26	13	35	0	0
Louisiana	321	378	224	219	5	2	22	0	0
Maine	2	30	0	1	0	0	1	0	0
Maryland	12	72	0	0	0	0	0	0	0
Massachusetts	14	306	53	48	5	0	0	0	0
Michigan*	44	344	106	94*	30*	0	8	0	0
Minnesota	14	53	106	92	18	0	20	0	0
Mississippi	159	664	368	313	55	0	0	0	0
Missouri	28	91	181	177	4	0	0	0	0
Montana*	15	67	3	2	1	0	0	0	0
Nebraska	422°	308	88	70	18	2	0	0	0
Nevada	4	79	3	3	0	0	3	0	0
New Hampshire	7	40	0	0	0	0	0	0	0
New Jersey	4	305	2	2	0	0	0	0	0
New Mexico	109	133	204	81	123	0	82	2: 109,800	2 (0-suspended)
New York	26	3,103	(9,910+) 396	396	0	0	16	1: 6,691,000	0
North Carolina	24	190	129	71	58	0	23	0	0
North Dakota	9	46	57	20	37	0	5	0	0
Ohio*	54	625	5	2	3	0	1	0	0
Oklahoma	121	67	11	6	5	0	11	0	0
Oregon	18	94	115	90	25	0	35	0	0
Pennsylvania	41	1,120	41	33	8	0	21	0	0
Rhode Island*	18	470	0	0	0	0	0	0	0
South Carolina	44	396	173	123	50	0	111	0	0
Tennessee	241	1,024	81	111	12	0	0	0	0
Texas	408	1,182	1,957	1,316	641	0	384	0	0
Utah*	75	163	55	50	5	0	47	0	0
Vermont	19	94	54	25	29	0	54	0	0
Virginia*	17	75	8	7	1	0	0	0	0
Washington*	27	221	289	263	26	0	0	0	0
West Virginia*	92	296	24	13	11	0	0	0	0
Wisconsin	9	59	36	36	0	0	0	0	0
Wyoming*	154	154	86	86	0	0	114	0	0
Dis. of Columbia	1	40	0	0	0	0	0	0	0
Puerto Rico	1	253	0	0	0	0	0	0	0
TOTAL	**3,603**	**17,324**	**6,562**	**4,983**	**1,800**	**19**	**1,497**	**6: 6,811,000**	**5: 2,200**

° includes number of towns supplied by large operators.

+ 9,514 record violations.

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Table 4

GAS PIPELINE ACCIDENTS INVESTIGATED BY STATE AGENCIES 1980

STATE	Number of Investigations	A/Caused by Corrosion	B/Caused by Damage by Outside Forces	C/Caused by Construction Defect or Material Failure	D/Caused by Other	E/Caused by Not Gas-Related (or Suicide)
Alabama	2	0	1	1	0	0
Arizona	6	0	5	1	0	0
Arkansas	0	0	0	0	0	0
California	55	2	36	12	5	0
Colorado	9	0	8	1	0	0
Connecticut	2	0	0	0	1	1
Delaware	0	0	0	0	0	0
Florida PSC	19	0	14	0	5	0
Florida OT	1	0	0	0	1	0
Georgia	1	0	1	0	0	0
Hawaii	1	1	0	0	0	0
Idaho	2	0	1	0	1	0
Illinois	2	0	0	1	1	0
Indiana	1	0	1	0	0	0
Iowa	2	1	1	0	0	0
Kansas	5	1	3	0	1	0
Kentucky	6	1	2	0	3	0
Louisiana	0	0	0	0	0	0
Maine	0	0	0	0	0	0
Maryland	1	1	0	0	0	0
Massachusetts	5	1	4	0	0	0
Michigan	11	3	4	3	1	0
Minnesota	8	1	2	3	2	0
Mississippi	0	0	0	0	0	0
Missouri	14	1	6	6	1	0
Montana	2	0	1	1	0	0
Nebraska	0	0	0	0	0	0
Nevada	4	0	2	2	0	0
New Hampshire	0	0	0	0	0	0
New Jersey	6	0	4	2	0	0
New Mexico	1	0	0	1	0	0
New York	13	1	7	2	3	0
North Carolina	4	0	3	0	1	0
North Dakota	1	0	1	0	0	0
Ohio	10	2	7	1	0	0
Oklahoma	1	1	0	0	0	0
Oregon	2	0	2	0	0	0
Pennsylvania	32	2	24	3	3	0
Rhode Island	1	0	0	0	1	0
South Carolina	4	0	3	1	0	0
Tennessee	9	1	2	3	1	2
Texas	34	8	13	9	4	0
Utah	2	0	2	0	0	0
Vermont	0	0	0	0	0	0
Virginia	2	0	2	0	0	0
Washington	4	0	3	1	0	0
West Virginia	9	0	3	1	1	4*
Wisconsin	13	0	7	1	4	1
Wyoming	1	0	1	0	0	0
Dist. of Columbia	2	0	1	0	1	0
Puerto Rico	0	0	0	0	0	0
TOTAL	**310**	**28**	**177**	**56**	**41**	**8**

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Table 5

1980 STATE JURISDICTION

+ = has jurisdiction Ø = none in state 0 = does *not* have jurisdiction s = seeking jurisdiction p = partial jurisdiction Δ = other state agency has jurisdiction

STATE	Gathering Lines in Non-rural areas	Transmission	Privately owned Distribution Public Utilities	Privately owned Facilities not Public Utilities Under State Law	Municipally Owned Distribution Systems	Other Publicly Owned Distribution Systems	Petroleum Gas	Master Meter	Offshore Facilities
Alabama	+	+	+	+	+	0	+	+	0
Arizona	Ø	+	+	0	+	0	+	0	Ø
Arkansas	+	+	+	+	+	+	+	+	Ø 0
California	+	+	+	0 s	0 s	0 Ø	0 s	0 s	+ Ø
Colorado	+	+	+	+	+	+	+	+	0
Connecticut	+ Ø	+	+	+	+	+	+	+	+ Ø
Delaware	+ Ø	+	+	0	0	0	+	+	0 Ø
Florida PSC	0 Δ	+	+	0	+	+	0 Δ	+	0
Florida OT	0	0	0	+	0	0	+	+	0
Georgia	Ø	+	+	+	+ p	0	0	+	Ø
Hawaii	Ø	+	+	Ø	Ø	Ø	+	0	Ø
Idaho	Ø	+	+	Ø	0 Ø	0	+	+	Ø
Illinois	+	+	+	+	+	+	+	+	+
Indiana	+	+	+	+	+	+	+	+	Ø
Iowa	Ø	+	+	+	+	Ø	+	+	Ø
Kansas	+	+	+	0	+	0	+	0	Ø
Kentucky	Ø	+	+	0	0	+	0	0	Ø
Louisiana	+	+	+	+	0	0	0	0 s	0
Maine	+	+	+	0	+	+	0 s	+	+
Maryland	0 Ø	0	+	+	+	0 Ø	0	0	0
Massachusetts	Ø	+	+	0 Δ	+	0 Ø	0	+ p Δ	Ø
Michigan	+	+	+	Ø	0 Ø	0 Ø	+	+	0 Ø
Minnesota	+	+	+	+	+	+	+ p Δ	+	Ø
Mississippi	+	+	+	+	+	+	+	+	+
Missouri	0 Ø	+	+	0	+	0	0 p	0	0 Ø
Montana	0	+	+	0	+	0	+	+	0 Ø
Nebraska	0	+	+	+	+	0	+	+	0
Nevada	0 Ø	+	+	0 s	0 Ø	0	+ p	0 s	0
New Hampshire	Ø	+	+	0 Ø	0 Ø	+	+	+	+
New Jersey	0 Ø	+	+	0	0 Ø	0 Ø	+ p	0	0 Ø
New Mexico	+	+	+	+	+	+	+	+	0
New York	+	+	+	+	+	+	+	0	+
North Carolina	Ø	+	+	+	+	0	+	+	Ø
North Dakota	+	+	+	+	+	Ø	+	+	Ø
Ohio	+	+	+	0	+	0 Ø	+	+	Ø
Oklahoma	+	+	+	+	+	0 Δ	0 Δ	0	Ø
Oregon	+ Ø	+	+	+	+ Ø	0 Δ	+	+	+
Pennsylvania	+ p	+ p	+	0	0 s	0	+ p	0 (indirect)	0 Ø
Rhode Island	Ø	+	+	+	Ø	Ø	+	+	+
South Carolina	Ø	+	+	+	+	+	0	+	Ø
Tennessee	+	+	+	+	+	+	+	+	Ø
Texas	+	+	+	+	+	+	+	+	+
Utah	+	+	+	+	+	+	+	+	0 Ø
Vermont	Ø	+	+	+	Ø	Ø	+	Ø	Ø
Virginia	Ø	+	+	0	0	Ø	+ p	0	Ø
Washington	0 Ø	+	+	+	+	0 Ø	+	+	+ Ø
West Virginia	+	+	+	+	+	+	+ Ø	+	+ Ø
Wisconsin	0 Ø	+	+	+	+	+	0	0 p	0 Ø
Wyoming	+	+	+	0	Ø	0	+	+	Ø
Dist. of Columbia	Ø	+	+	Ø	Ø	0	Ø	0	Ø
Puerto Rico	+	+	+	Ø	Ø	Ø	+	Ø	Ø
TOTAL	**27**	**49**	**50**	**29**	**33**	**19**	**39**	**33**	**12**

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Table 6

QUALIFICATIONS OF STATE PERSONNEL (TECHNICAL) 1980

STATE	No. Cat. A	No. Cat. B	No. Cat. C	No. Cat. D	No. Cat. E	Total No. Inspectors
Alabama	0	0	5	1	0	6
Arizona	0	3	0	0	0	3
Arkansas	0	0	1	2	0	3
California	6	0	0	0	0	6
Colorado	2	0	0	0	0	2
Connecticut	2	1	0	0	0	3
Delaware	1	0	0	0	0	1
Florida PSC	4	0	1	0	0	5
Florida OT	0	0	6	0	0	6
Georgia	0	1	1	0	2	4
Hawaii	0	0	0	1	0	1
Idaho	0	1	0	0	0	1
Illinois	0	3	1	4	0	8
Indiana	1	0	2	0	0	3
Iowa	0	1	2	0	0	3
Kansas	0	1	2	0	0	3
Kentucky	0	2	0	1	0	3
Louisiana	1	5	1	0	0	7
Maine	0	1	0	0	0	1
Maryland	0	1	0	1	0	2
Massachusetts	2	0	2	5	0	9
Michigan	4	7	1	0	0	12
Minnesota	0	0	0	0	15	15
Mississippi	0	0	2	0	0	2
Missouri	0	2	2	0	0	4
Montana	1	1	0	0	0	2
Nebraska	0	0	1	2	0	3
Nevada	0	2	0	0	0	2
New Hampshire	1	0	0	0	0	1
New Jersey	0	4	0	0	0	4
New Mexico	0	2	0	0	0	2
New York	2	16	6	3	0	27
North Carolina	0	2	0	1	0	3
North Dakota	0	1	0	0	0	1
Ohio	0	1	2	3	0	6
Oklahoma	1	1	1	0	0	3
Oregon	0	1	0	1	0	2
Pennsylvania	2	3	2	0	0	7
Rhode Island	3	0	1	2	1	7
South Carolina	0	1	2	0	0	3
Tennessee	0	5	0	0	0	5
Texas	6	2	0	2	5	15
Utah	0	1	1	0	0	2
Vermont	1	0	0	0	0	1
Virginia	0	4	0	0	0	4
Washington	1	1	0	0	0	2
West Virginia	1	0	1	1	0	3
Wisconsin	0	3	0	0	0	3
Wyoming	4	0	0	0	0	4
Dist. of Columbia	0	1	0	0	0	1
Puerto Rico	0	0	5	0	1	6
TOTAL	**46**	**81**	**51**	**30**	**24**	**232**

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STATE INSPECTOR QUALIFICATION CATEGORIES

A. Has an engineering degree from an accredited engineering school or is a registered professional engineer, with a minimum of three years of experience in gas or liquid transmission and/or distribution pipelines.

B. Has an engineering degree from an accredited engineering school, or is a registered professional engineer, or has over ten years of gas or liquid transmission and/or distribution experience which demonstrates in-depth knowledge of pipeline engineering technology, particularly as related to pipeline safety.

C. Has a college degree or over five years of experience as a state pipeline inspector monitoring gas or liquid operators in regard to their compliance with state and Federal pipeline safety regulations.

D. Has less than five years of experience as a state pipeline inspector monitoring gas or liquid operators in regard to their compliance with state and Federal pipeline safety regulations.

E. Has less than one year of experience as a state pipeline inspector monitoring gas or liquid operators in regard to their compliance with state and Federal pipeline safety regulations.

NOTE: The experience listed in categories A and B refers to actual on-the-job experience working for a pipeline company involved with gas or liquid distribution, transmission, or both. Individuals with no actual pipeline experience still quality for category B as long as they have an engineering degree from an accredited college or university or are registered by the respective state as a registered professional engineer.

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Table 7

STATE PERSONNEL INVOLVED IN GAS PIPELINE SAFETY DURING 1980 (as of Dec. 31, 1980)

STATE	Administrative / Supervisory		Technical		Clerical	
	Number of Personnel	Person Years	Number of Personnel	Person Years	Number of Personnel	Person Years
Alabama	1	1.00	6	6.00	1	1.00
Arizona	5	.10	3	.88	2	1.00
Arkansas	2	.53	3	2.80	2	.66
California	2	1.45	6	5.05	1	1.00
Colorado	1	.05	2	2.00	2	.15
Connecticut	1	.13	3	1.20	1	.29
Delaware	1	.25	1	.25	2	.30
Florida PSC	2	1.05	5	5.00	1	.50
Florida OT	2	.37	6	1.07	3	.60
Georgia	2	1.00	4	3.20	1	1.00
Hawaii	3	.09	1	.50	5	.05
Idaho	1	.50	1	.50	1	.10
Illinois	2	.90	8	7.20	1	1.00
Indiana	1	.75	3	2.25	0	0
Iowa	1	.12	3	1.40	1	.03
Kansas	4	.18	3	3.00	4	.03
Kentucky	1	1.00	3	3.00	1	1.00
Louisiana	5	4.10	7	5.40	5	3.10
Maine	1	.04	1	.81	1	.02
Maryland	1	.20	2	1.75	1	.25
Massachusetts	1	.15	9	2.11	2	.50
Michigan	1	.30	12	4.09	1	.46
Minnesota	1	1.00	15	1.50	2	1.00
Mississippi	1	1.00	2	2.00	1	.75
Missouri	3	.75	4	3.00	1	.50
Montana	4	.10	2	.60	1	.05
Nebraska	1	.30	3	2.70	1	.50
Nevada	1	.05	2	1.05	1	.10
New Hampshire	0	0	1	.88	1	.83
New Jersey	2	1.05	4	3.00	4	.40
New Mexico	1	1.00	2	2.00	1	.90
New York	3	2.58	27	24.41	1	.95
North Carolina	3	.80	3	2.25	1	1.00
North Dakota	1	—	1	.50	3	.06
Ohio	3	1.22	6	5.20	1	.50
Oklahoma	1	.70	3	2.30	1	1.00
Oregon	3	.31	2	1.85	1	.50
Pennsylvania	1	.06	7	7.00	1	.07
Rhode Island	3	.46	7	3.48	2	1.04
South Carolina	1	.80	3	3.00	1	—
Tennessee	1	.80	5	5.00	1	.80
Texas	7	2.50	15	9.80	6	5.40
Utah	3	.25	2	.95	1	.50
Vermont	1	.60	1	.30	1	.10
Virginia	2	.20	4	1.53	3	.18
Washington	1	.20	2	1.45	3	.13
West Virginia	2	.85	3	2.25	1	1.00
Wisconsin	1	.19	3	2.93	2	.25
Wyoming	2	.90	4	1.45	1	—
Dist. of Columbia	1	.25	1	.75	1	.50
Puerto Rico	2	.74	6	2.72	1	.32
TOTAL	**97**	**33.92**	**232**	**155.31**	**85**	**32.37**

GAS PIPELINE FAILURES AND CASUALTIES

The Materials Transportation Bureau maintains a reporting system to gather and analyze accident and operations data from pipeline operators and carriers. The information is used to identify safety problems and determine areas where additional rulemaking might be required.

1980 Accident Data

In 1980, 11 fatalities and 310 injuries resulted from 1,996 gas pipeline system failures. Failures increased only 1 percent and fatalities decreased by 75 percent compared to those reported in 1979.

Damage by outside forces accounts for the majority of gas system failures—68 percent of failures reported in 1980. The following charts reveal that corrosion and other causes were responsible for 11 percent and 12 percent, respectively, of gas system accidents. Construction defects or material failure were responsible for 9 percent of gas system accidents.

Table 8

ACCIDENTS AND CASUALTIES REPORTED BY GAS SYSTEM OPERATORS DURING CY 1980

Distribution Systems

Cause	No. of Failures	Fatalities	Injuries
Corrosion	115	1	15
Damage by Outside Forces	1,056	1	140
Construction Defect or Material Failure	101	6	39
Other Causes	195	1	75
TOTAL	**1,467**	**9**	**269**

Table 9

TRANSMISSION AND GATHERING SYSTEMS

Cause	No. of Failures	Fatalities	Injuries
Corrosion	102	0	3
Damage by Outside Force	305	0	10
Construction Defect or Material Failure	88	1	7
Other Causes	34	1	21
TOTAL	**529**	**2**	**41**
GAS INDUSTRY TOTALS	**1,996**	**11**	**310**

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Table 10

Summary of Gas Pipeline Accidents and Casualties Reported from 1970—1980 as Required by CFR Part 191

Year	Distribution			Transmission and Gathering			Total		
	Failures	Fatalities	Injuries	Failures	Fatalities	Injuries	Failures	Fatalities	Injuries
1970	676	21	202	343	1	16	1,019	22	218
1971	875	42	365	410	3	24	1,258	45	389
1972	884	28	294	409	6	36	1,293	34	330
1973	893	33	333	471	2	19	1,364	35	352
1974*	1,017	20	314	460	4	20	1,477	24	334
1975*	979	8	220	394	6	17	1,373	14	237
1976*	1,036	53	319	543	10	47	1,579	63	366
1977*	1,530	29	420	466	7	30	1,996	36	450
1978*	1,555	20	320	533	11	86	2,088	31	406
1979*	1,520	33	313	450	12	93	1,970	45	406
1980*	1,467	9	269	529	2	41	1,996	11	310

* Includes data from telephonic reports to the Materials Transportation Bureau reported pursuant to section 191.5. Data from telephonic reports were not inlcuded in accident/casualty data for years 1970—1973.

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FIGURE 1

GAS PIPELINE ACCIDENTS BY CAUSE 1980

TOTAL - 1,996

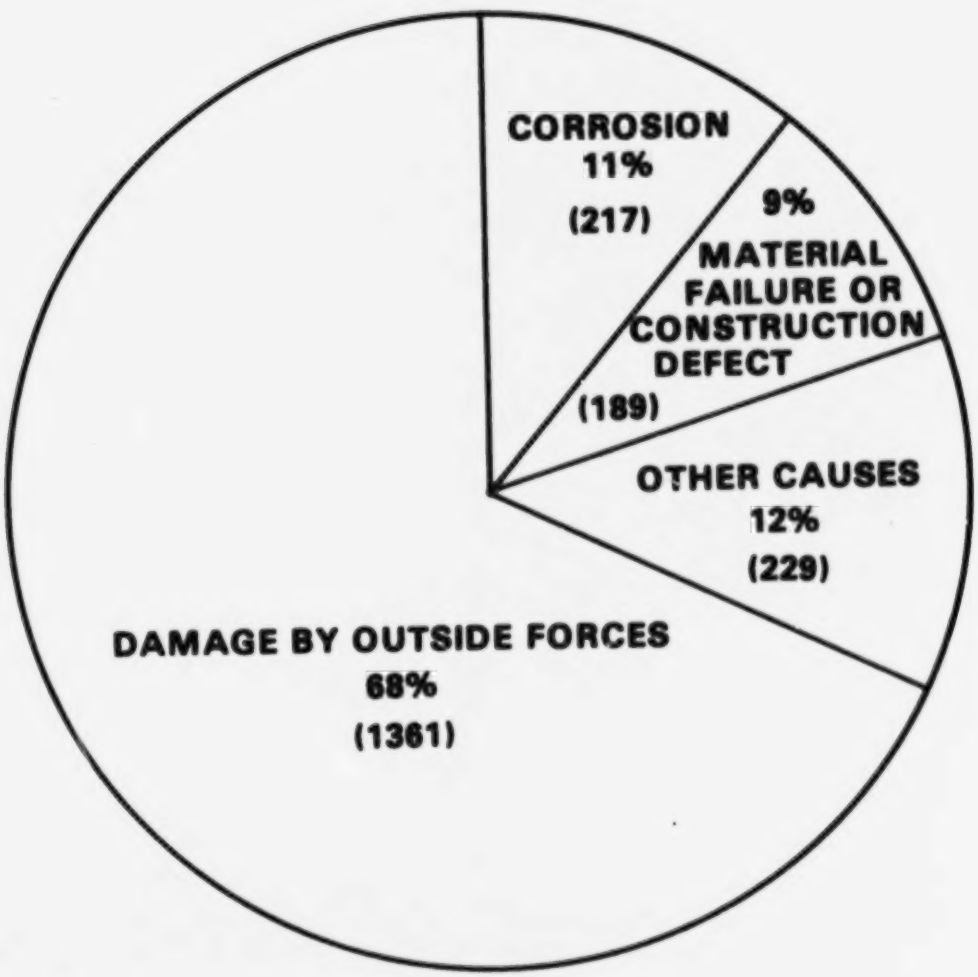
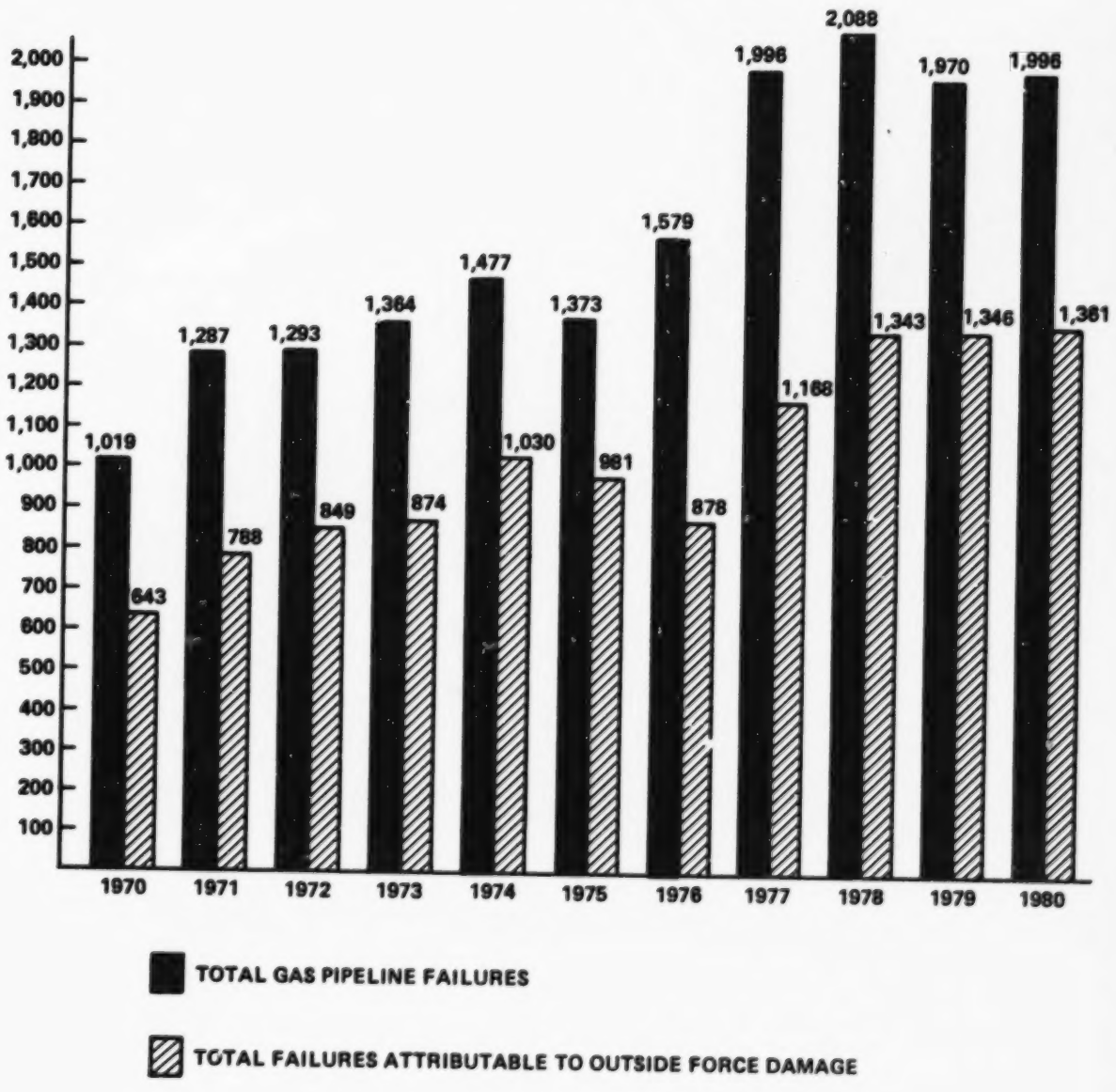


FIGURE 2

GAS PIPELINE FAILURES CAUSED BY OUTSIDE FORCE DAMAGE 1970-1980



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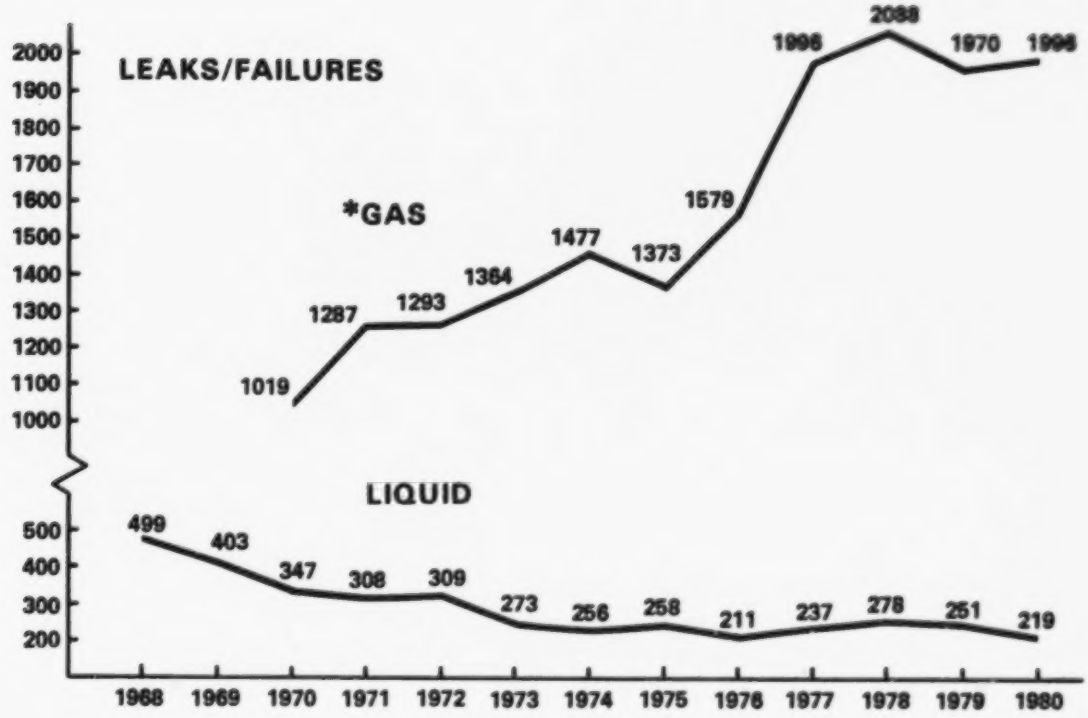
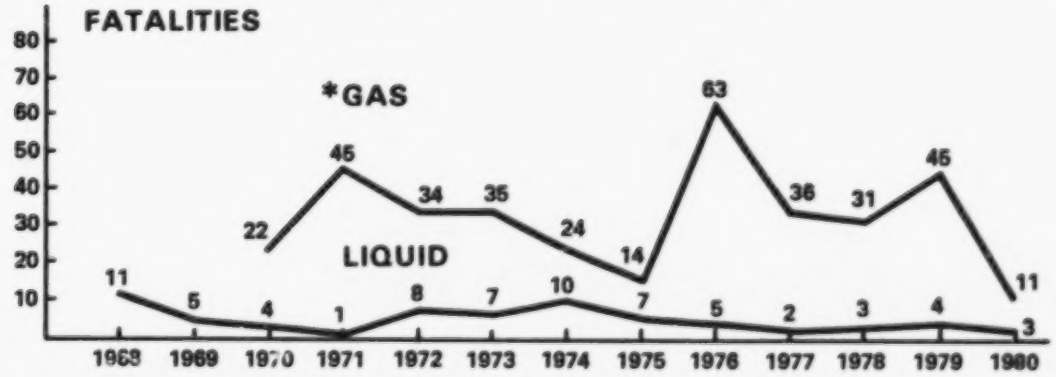
Graph A

1968-1980 EXPERIENCE LIQUID AND GAS PIPELINE LEAKS/FAILURES



Graph B

1968-1980 EXPERIENCE LIQUID AND GAS PIPELINE FATALITIES



*GAS PIPELINE SAFETY PROGRAM INITIATED IN 1970

GAS PIPELINE FAILURES AND INVESTIGATIONS

Gas Failures Investigated by MTB

Significant gas pipeline failures are investigated by MTB and cooperating state agencies each year to ascertain that the Federal safety standards are being properly complied with or to determine if additional regulatory action should be initiated.

During 1980, MTB staff engineers cooperated with state agency personnel in conducting three accident investigations—at Dublin, Georgia (May 2); the Bronx, New York (June 11); and East Baton Rouge Parish, Louisiana (August 2). A brief description of each incident follows.

- Three people were killed, and four people were injured by a natural gas ignition on May 2 in Dublin, Georgia. Probable cause was determined to be a non-anchored 8-inch pipe which had pushed out of an 8-inch style 38 Dresser coupling located approximately 13 feet 10 inches from the exposed tie-in weld. Workmen were in the tie-in bell hole preparing to apply hot-wrap coating to the finished tie-in. They were using a propane tank to heat the tape coating when the pipe pushed out of the Dresser coupling. The pipeline was being operated at approximately 300 psig at that time.

- An explosion at a drycleaning and laundromat in the Bronx, New York, killed 1 person and injured 13 on June 11. Probable cause was found to be a crack in an 8-inch cast iron low pressure gas main.

- A rupture and ignition occurred on a segment of a 24-inch Florida Gas Transmission mainline on August 2 near Zachary, Louisiana. Probable cause was believed to be a delayed-failure mechanism such as hydrogen stress cracking, or stress corrosion cracking.

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PIPELINE SAFETY RESEARCH AND DEVELOPMENT PROGRAM

The Materials Transportation Bureau's research and development program provides technical support for development, modification, and interpretation of the pipeline safety regulations and for enforcement activities. Research is initiated to derive answers to special problems—analysis of design criteria for pipeline repair for example. Project highlights for 1980 include:

Fracture Mechanics Study

The National Bureau of Standards (NBS) continued to develop weld acceptance and flaw size and shape criteria for evaluating pipeline circumferential welds under MTB funding. NBS has also begun to develop weld acceptance criteria for use during construction of the Alaska Natural Gas Pipeline.

Safety of Arctic Pipelines

Woodward-Clyde Consultants continued work on a contract to provide the Office of Pipeline Safety Regulation with an evaluation of the problems to be anticipated in Arctic pipeline design, construction, testing, inspection, operation and maintenance. This study will review the current state of the art, identify problem areas in Arctic pipelines and feasible solutions to these problems, and make recommendations for any changes or additions that may be needed to Parts 192 and 195.

Evaluation of Existing Pipelines with Respect to Corrosion Control

The Harco Corporation began a study of the feasibility and methods used for evaluating corrosion control on cathodically protected urban pipelines that are under paving or in areas where stray currents exist. This work is being done to verify the appropriateness of the existing requirements for electrical surveys to be conducted on pipelines that are under cathodic protection and located under paving.

Damage and Confinement in Offshore Pipelines

The California Institute of Technology began a study under the Department's University Research Program to determine the effect of damage, particularly buckling, on offshore pipelines. Progress is being monitored by MTB technical staff.

Analysis of Design Criteria for Alyeska Pipeline Repairs

Under agreement with MTB, the NBS finalized a report on the design criteria for repair sleeves installed on failed sections of pipe of the Trans-Alaska crude oil pipeline. MTB is continuing to study these repairs to assure that they are structurally sound and in conformance with 49 CFR Part 195 and other standards. Repaired sections of the Trans-Alaska oil pipeline at Mileposts 166 and 734 have been monitored during the year and a half since the breaks in 1979 and no problems have occurred. As precautionary measures, 58 additional settlement rods have been installed in the milepost 166 area. Corings from holes drilled in 1980 have confirmed the hypothesis that the 1979 failures were caused by thawing permafrozen soil and ice. Subsurface studies are continuing in other possibly susceptible locations to assure pipeline stability.

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TRAINING AND SAFETY INFORMATION

In 1980, MTB continued efforts to inform state agencies, pipeline industry, engineers, contractors, labor groups, pipeline equipment and service suppliers, and the general public on matters relating to pipeline safety regulatory and compliance issues. Information provided included: (1) copies of the Federal pipeline safety regulations and notices of proposed rulemaking; (2) the Pipeline Safety Newsletter; (3) formal presentations to state agency and industry groups; (4) safety information for use by industrial and general publications; and (5) reports on the results of studies funded by MTB on different aspects of pipeline safety. In addition, the Bureau sponsored several pipeline safety training courses conducted at DOT's Transportation Safety Institute (TSI).

Information Dissemination

Continued publication and distribution to more than 4,800 agencies, firms, and individuals of the Pipeline Safety Newsletter provided an important vehicle for the dissemination of regulatory and technical information. The Newsletter contains information about the Department's pipeline safety requirements and programs, and technical material gleaned from studies conducted by the industry, research organizations, and public groups. MTB also responded to specific requests for data from Congressional offices, the industry, state agencies, the press, and interested individuals.

MTB Reports Available

In 1980, MTB arranged through the National Technical Information Service (NTIS) for distribution of documents from completed MTB research and development efforts. A complete list of reports dealing with pipeline safety is available through NTIS.

Safety Training Program

The Bureau's safety training program activities continued with a high degree of success in 1980 under joint MTB and state agency staff direction. The Transportation Safety Institute offered courses on Failure and Noncompliance Investigative Techniques, Joining of Gas Pipeline Materials, Corrosion Control Systems, Pressure Regulation and Overpressure Protection, and Regulation Compliance Requirements. The courses were attended by a total of 305 Federal, state, and industry employees (see following tables).

Table 11

Pipeline Safety Courses Conducted by TSI 1980

	No. of Classes	Students Trained		
		State	Federal & Other	Total
Failure and Noncompliance Investigative Techniques	2	21	4	25
Joining of Gas Pipeline Materials	2	24	2	26
Gas Pressure Regulation and Overpressure Protection	2	38	3	41
Safety Evaluation of Gas Pipeline Systems	2	31	1	32
Safety Evaluation of Gas Pipeline Corrosion	2	25	3	28
Control System Fundamentals				
Safety Evaluation of Gas Pipeline Corrosion Control Systems Advanced	1	13	0	13
Liquefied Natural Gas Safety Technology & Inspection	2	27	13	40
TOTAL	**13**	**179**	**26**	**205**

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Table 12

Industry Training Courses 1980

	No. of Classes	Students Trained: Federal & Other
Regulations Compliance Requirements for Gas Pipeline Operators (Industry)	2	39
Gas Pipeline Failure Investigation (Industry)	2	33
Safety Evaluation of Gas Pipeline Corrosion Control Systems (Industry)	2	32
TOTAL	**6**	**104**

The MTB-sponsored training program enables participating state agencies to increase both the scope and quality of their gas pipeline safety programs, while providing MTB personnel with an opportunity for direct contact with state and industry representatives to explain the Federal regulations and provide technical assistance.

Table 13

Summary for 1980 Training Conducted by TSI

No. of Resident Classes	No. of Seminars	No. of Resident Students	Total No. Trained
19	0	309	309

TECHNICAL PIPELINE SAFETY STANDARDS COMMITTEE

The Department's Technical Pipeline Safety Standards Committee (TPSSC) is established under Public Law 90-481, the Natural Gas Pipeline Safety Act of 1968. The Committee functions as an advisory body to the Materials Transportation Bureau with responsibility for evaluating proposed gas pipeline safety standards and reporting on their feasibility, reasonableness, and practicability. Committee membership is comprised of five representatives of government, including two state commissioners, four representatives from the natural gas industry, and six representatives from the general public. Qualifications for membership include experience in the regulation of transportation of gas, or training in related fields of engineering.

The TPSSC met three times in 1980 in Washington, D.C., to review and report on proposed rule changes to the Federal gas pipeline safety standards. On April 15-17, the Committee met to consider the following notices of proposed rulemaking: (1) Docket PS-57, Notice 1, Monitoring Gas Odor Levels; (2) Docket PS-58, Notice 1, Temperature Limits on Cold Expanded Steel Pipe; (3) Docket PS-59, Notice 1, Damage Prevention Program; (4) Docket PS-60, Notice 1, Hot Taps in Gas Pipelines; and (5) Docket PS-62, Notice 1, Leakage Surveys. On June 17-20, the Committee met to consider the following notices of proposed rulemaking: (1) Docket PS-46, Notice 5, LNG Facilities Federal Safety Standards; and (2) Docket PS-65, Notice 1, Incorporation by Reference. The Committee also considered several matters for future rulemaking, including maps and records, line marking at navigable waterways, leak classifications, and blasting near pipelines. On December 9-10, the Committee met in formal discussion to consider a notice of proposed rulemaking on Qualification of Metallic Components (Docket PS-64, Notice 1), and informally discussed Docket PS-66, Notice 1, an advanced notice of proposed rulemaking on Placing Longitudinal Weld Seams in Upper Half of Pipe. In addition, they discussed proposed safety regulatory projects on excess flow valves in gas distribution lines/services and reporting LNG facility events.

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ALASKA NATURAL GAS TRANSPORTATION SYSTEM

Introduction

The Alaska Natural Gas Transportation System (ANGTS) is the largest privately-financed construction project ever undertaken. ANGTS has been given special status by the Alaska Natural Gas Transportation Act of 1976. The act provided for appointment by the President of a Federal Inspector who has the authority to enforce pipeline safety regulations for ANGTS as part of his project oversight responsibilities.

Under Executive Order 12142, which established the Office of the Federal Inspector for construction of the ANGTS, each Federal agency having statutory responsibilities over any aspect of the ANGTS is required to appoint an Agency Authorized Officer (AAO) to represent that authority on all matters pertaining to preconstruction, construction, and initial operation of the system. The AAO's are detailed to and located within the Office of the Federal Inspector.

The Materials Transportation Bureau has a major role in this project. The Department of Transportation's Agency Authorized Officer (AAO), an MTB official, represents all DOT agencies and is responsible for monitoring and expediting all project related activities within DOT. The AAO is responsible for interacting with the Federal Inspector (FI) and is responsible for reviewing the effort of the FI's staff to assure that DOT's enforcement policies and procedures are carried out.

The Department's AAO expedites DOT permits and authorizations, reviews and monitors FI compliance reports, participates in preparation of FI procedural guides and manuals, assures FI staff receives proper training in regulation enforcement, and participates in special enforcement actions. During project development this year the AAO has actively participated in resolving technical issues spelling the National Bureau of Standards, the Cold Regions Engineering Technical Committee, and by directly witnessing full scale and laboratory testing programs. Working relationships and agreements are being established by the AAO with the FI and within DOT. The purpose of these working agreements is to provide an orderly framework for expediting all project related activity within DOT.

The Project

The Alaska Natural Gas Transportation System (ANGTS) is being developed as four major pipeline segments. The Alaskan segment will be constructed and operated by Northwest Alaskan Pipeline Company, the Canadian segment by four Canadian companies, an Eastern leg (from Montana to Chicago) by Northern Border Pipeline Company, and a Western Leg (from Idaho to San Francisco) by Pacific Gas. The 4,753 mile system will have a nominal capacity of 2.6 billion cubic feet of gas per day.

Parts of the Canadian segment and the Eastern and Western Legs are being constructed early on "prebuilt" in order to transport excess gas from Alberta to the U.S. prior to completion of the Alaskan segment. Western Leg construction started in 1980; the Eastern Leg will begin construction in early 1981. The Alaskan segment is scheduled to start construction in 1983 and be in operation in 1986. The Canadians are moving to "prebuild" to match completion with the Western and Eastern Legs.

MTB's Technical Involvement

In 1980 MTB witnessed full-scale pipe burst tests being conducted as part of a program sponsored by Northwest to determine the behavior of propagating ductile fractures in large diameter pipe under arctic conditions. This testing is designed to provide the specific data needed to select the means of preventing such failures on the Alaska segment of the ANGTS. The preventive measures being studied include high toughness pipe and crack arrestors.

Insulated pipe bend tests and cold room bend tests were conducted on full size 48-inch pipe and were witnessed by MTB. These tests were designed to see if insulated pipe can be bent without damage to the jacket and to assure the acceptability of the heat fusion epoxy coating. An acceptable method for bending insulated pipe is still being sought.

DOT Internal Coordination

The Alaskan offices of the Federal Aviation Administration, the United States Coast Guard and the Alaskan Railroad were visited by the AAO in 1980 to establish working relationships for expediting permits and other agency authorizations relating to the ANGTS.

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OUTSTANDING PROBLEMS

Several problem areas persist as impediments to a fully effective Federal pipeline safety program.

Consensus Standards

The Federal standards incorporate by reference many documents commonly called "consensus standards" that are prepared by non-government organizations. The references to non-government documents simplify the task of regulating highly technical subjects, but they present problems for MTB and the regulated industry. Often the documents are not written in regulatory language, making them difficult to enforce, and later-published editions cannot be used by the regulated pipeline industry until MTB approves the practice by referencing those later editions.

To deal with the problem, MTB is hastening the process of updating referenced standards to later editions to avoid unnecessary hindrance to the industry's use of safer and more efficient practices. In addition, MTB is working to extend its current use of performance standards, which prescribe safety objectives rather than specific practices for many of the areas now regulated through references to consensus standards.

Participation of States in Training Program

The Federal grant-in-aid program was established to encourage continued cooperation by states that qualify with assistance in meeting their expenses for gas pipeline safety programs. The program allows states to apply to the Department for reimbursement of up to 50 percent of their expenditures for gas pipeline safety programs.

There now exists a situation in which MTB cannot, because of insufficient funds, provide 50 perent of funding for such programs. Therefore, a decrease in state participation and training of state personnel, and in the effectiveness of the overall program can be expected to result.

MTB will continue to provide states with an effective and comprehensive program for pipeline safety and to develop and initiate new programs with the resources that are available.

Outside Force Damage

Outside force damage continues to remain one of the primary causes of significant pipeline incidents. There are still many areas that do not have legislation designed to reduce the number of incidents caused by outside forces.

Master Meter Systems

The NGPSA gives the Department jurisdiction over petroleum gas (also known as LP-gas) distribution systems and over small natural gas systems operated by individuals or companies in connection with the rental or lease of housing. These systems are supplied gas from local utilities by purchase agreements through a master meter—a device which measures large quantities of gas.

Since many of the safety problems that confront operators of gas distribution systems prevail whether the system is a large gas utility, an LP-gas system, or a master meter system, the existing Federal standards were adopted as general safeguards for all three. This policy has not worked well for either the industry or government because it does not take into account the many physical dissimilarities between the large and small systems, and the capabilities of those who own and operate them.

MTB expects to alleviate these difficulties by developing a compliance manual tailored to fit the characteristics of LP-gas and master meter systems which will be easier to follow and less burdensome to enforce.

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REPORT ON THE ADMINISTRATION OF THE HAZARDOUS LIQUID PIPELINE SAFETY ACT

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LIQUID PIPELINE SAFETY STANDARDS

MTB plans to issue a final rule to amend the liquid pipeline safety regulations in Part 195 to conform with and reflect its issuance under the authority of the Hazardous Liquid Pipeline Safety Act of 1979 (Title II of Pub. L. 96-129, November 30, 1979) (HLPSA) and incorporate a number of HLPSA provisions into Part 195. Briefly, the document will:

1. Cite the HLPSA as the statutory authority for Part 195;
2. Incorporate HLPSA terminology and definitions into Part 195;
3. Restrict the application of Part 195 to pipelines moving petroleum, petroleum products, or anhydrous ammonia in interstate or foreign commerce;
4. Define interstate and intrastate pipeline facilities;
5. Increase from $1,000 to $5,000 the dollar amount of property damage that triggers operator accident reporting;
6. Provide for the preparation, maintenance, and carrying out of inspection and maintenance plans as required by the HLPSA; and
7. Incorporate current DOT organization designations.

Four amendments were made to the Federal liquid pipeline standards, 49 CFR Part 195, during the year:

Transportation of Liquids by Pipeline; Addition of Water to Pipelines Transporting Anhydrous Ammonia (45 FR 8323). On January 30, 1980, MTB proposed new regulations for inclusion in Part 195 to require the addition of water in the amount of 0.2 percent minimum by weight to anhydrous ammonia being transported by interstate or intrastate pipeline facilities, as those terms are defined in the Hazardous Liquid Pipeline Safety Act of 1979. The water is needed to inhibit stress corrosion cracking in the pipeline, a type of cracking caused by a combination of stress and electrochemical corrosion (see Appendix B).

Transportation of Liquids by Pipeline; Hydrostatic Testing Liquid Pipelines (45 CFR 16230). On March 4, 1980, MTB proposed to reduce the 24-hour hydrostatic hold period in Subpart E. A two-part test was proposed: a 4-hour strength test at 125 percent of maximum operating pressure was proposed for all hazardous liquid pipelines (both interstate and intrastate pipeline facilities as these terms are defined by the Hazardous Liquid Pipeline Safety Act of 1979); additionally, a 4-hour leak test at 110 percent of maximum operating pressure was proposed for those pipelines not visually inspected for leakage while under the strength test. Data indicated the 24-hour hold period was necessary for safety (see Appendix B).

Testing Highly Volatile Liquid Pipelines. Effective October 8, 1980, the regulations were amended disallowing onshore interstate pipeline facilities (as that term is defined in the Hazardous Liquid Pipeline Safety Act of 1979) constructed before January 8, 1971, to transport highly volatile liquids (HVL) unless they have been hydrostatically tested in accordance with Subpart E of Part 195 or do not operate at a pressure that exceeds 80 percent of any test on operating pressure which has been held for four continuous hours. This rule reduces the potential for severe HVL pipeline accidents caused by latent material and construction defects.

Seams on Adjacent Pipe Lengths. Effective September 8, 1980, a final rule was issued which revoked § 195.218 requiring that seams on adjacent pipe lengths be offset. This action took place because the pipe manufacture and welding technology has advanced sufficiently to make the requirement of this section unnecessary (see Appendix B).

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LIQUID PIPELINE FAILURES AND STATISTICS

Failure Statistics

In 1980, 219 liquid pipeline failures resulted in three fatalities, 15 injuries, and a total commodity loss of 289,445 barrels. The following chart indicates that outside force damages in the form of equipment-caused line ruptures accounted for 38 percent of liquid pipeline accidents. Pipeline corrosion was cited as the accident cause in 23 percent of the liquid incidents. Crude oil was spilled in 49 percent of the reported incidents, gasoline in 19 percent and liquefied petroleum gas in 11 percent of reported incidents. Detailed accident data appear in the following tables.

Table 14

Summary of Liquid Pipeline Accidents and Casualties from 1971 to 1980

Year	Failures	Fatalities	Injuries	Total Commodity Loss (bbl.)
1971	310	1	8	243,311
1972	306	1	16	344,350
1973	273	7	10	377,672
1974	256	10	6	292,001
1975	254	7	17	318,278
1976	212	5	4	249,690
1977	237	3	15	224,794
1978	256	3	10	280,794
1979	251	4	13	548,669
1980	219	3	12	289,445

Table 15

Liquid Pipeline Accident Summary by Cause January 1, 1979, through December 31, 1980

					Property Damage ($)				*Deaths*		*Injuries*	
Cause of Accident Operation Accidents	*No. of Accidents*	*% of Total*	*Loss (Barrels)*	*% of Total*	*Carrier*	*Other*	*Total*	*% of Total*	*Carrier Employees*	*Non Employees*	*Carrier Employees*	*Non Employees*
Internal Corrosion	9	4.1	2,620	9	3,435	8,500	11,935	2	0	0	0	0
External Corrosion	42	19.2	14,274	4.9	40,021.75	18,000	58,021.75	1.1	0	0	0	0
Defective Weld	4	1.8	5,232	1.8	689.74	51,000	51,689.74	1	0	0	0	4
Incorrect Operation by Carrier Personnel	13	5.9	21,970	7.6	16,813	150,000	166,813	3.1	0	0	0	0
Defective Pipe	8	3.7	10,915	3.8	11,327	9,250	20,577	4	0	0	0	0
Equipment Rupturing Line	84	38.4	140,313	48.5	365,885.50	1,012,875	13,789,605	25.4	0	1	0	4
Other	59	26.9	94,121	32.5	3,638,186	95,380	3,733,566	68.8	1	1	5	2
Unknown	0	0	0	0	0	0	0	0	0	0	0	0
Totals	**219**	**100.0**	**289,445**	**100.0**	**4,078,358**	**1,345,005**	**5,421,363**	**100.0**	**1**	**2**	**5**	**10**

Table 16

Liquid Pipeline Accident Summary by Commodities Involved For the Year 1980

Cause of Accident Operation Accidents	No. of Accidents	% of Total	Loss (Barrels)	% of Total	Property Damage ($)			% of Total	Deaths		Injuries	
					Carrier	Other	Total		Carrier Employees	Non Employees	Carrier Employees	Non Employees
Crude Oil	108	49.3	147,777	51.1	482,126	488,924	971,050	17.9	0	1	0	0
Alkyate	0	.0	0	0	0	0	0.0	0	0	0	0	
Anhydrous Ammonia	1	.5	3,606	1.2	100	1,800	1,900	0.0	0	0	0	0
Jet Fuel	5	2.3	3,214	1.1	73	100	173	0.0	0	0	0	0
Gasoline	42	19.2	30,277	10.5	3,175,567	397,670	3,573,237	65.9	1	1	3	1
Oil and Gasoline	2	.9	9,794	3.4	602	0	602	0.0	0	0	0	0
Turbine Fuel	3	1.4	2,382	.1	67	45,500	46,170	.9	0	0	0	0
Keosene	1	.5	8,000	2.8	934	0	934	0.0	0	0	0	0
Diesel Fuel	6	2.7	2,841	1.0	5,131	4,550	9,681	.2	0	0	0	0
Fuel Oil	13	5.9	8,783	3.0	65,988	2,625	68,613	1.3	0	0	0	0
Condensate	1	.5	75	0.0	0	0	0	0.0	0	0	0	0
LPG	24	10.9	50,881	17.6	172,236	277,780	450,016	8.3	0	0	2	8
NGL	11	5.0	20,798	7.2	153,531	125,556	279,087	5.1	0	0	0	1
Unknown	2	.9	1,017	.4	19,400	500	19,900	.4	0	0	0	0
Totals	**219**	**100.0**	**289,445**	**100.0**	**4,076,358**	**1,345,005**	**5,421,363**	**100.0**	**1**	**2**	**5**	**10**

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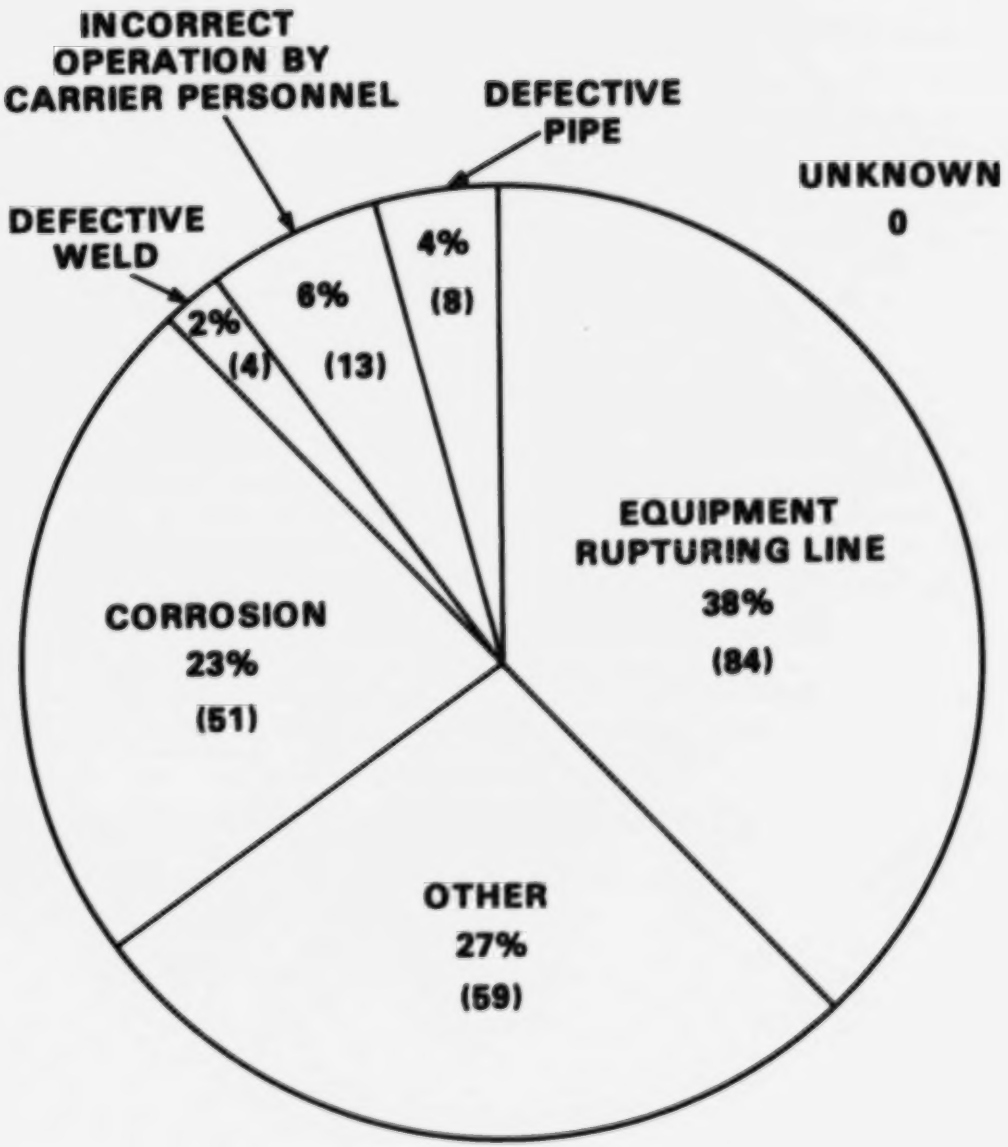
FIGURE 3

LIQUID PIPELINE ACCIDENTS BY CAUSE 1980

TOTAL - 219



ENFORCEMENT ACTIVITY

The Hazardous Liquid Pipeline Safety Act of 1979 (HLPSA) (P.L. 96-129) authorized the Department to establish a cooperative program with state regulatory agencies to enforce the liquid pipeline safety regulations. This program, modelled on the state gas pipeline safety program, would allow states to exercise jurisdiction over intrastate liquid pipelines as determined by state laws. Preliminary steps to establish this program were taken during the year.

Until a state program is established, jurisdiction over liquid pipeline operators remains with the Federal government. The HLPSA granted the Department authority, not previously held, to impose civil penalties and other enforcement actions for violations to the following principal areas to assure that liquid pipeline operators met the requirements of the regulations in 1980:

- Inspecting and monitoring hazardous liquid pipeline systems under MTB jurisdiction to assure that operators comply with Federal pipeline safety regulations.
- Investigating pipeline failure incidents to determine whether violations of Federal standards occurred or if revisions or additions to regulations are needed.

Inspection and Enforcement Program

During the year, MTB inspected 76 hazardous liquid pipeline systems expending 215 person-days. Enforcement actions were initiated against 21 liquid pipeline operators for violations of the Federal safety regulations.

Five actions involving the preliminary assessment of a civil penalty or the issuance of a proposed compliance order were initiated. After considering arguments and information submitted by the Regional personnel and the operator, the Associate Director for Operations and Enforcement assessed a civil penalty of $1,000 against one operator. The Regional Chiefs sent 16 warning letters to operators for violations of the regulations that did not warrant the imposition of more stringent enforcement actions. One operator paid a $1,000 civil penalty during the year. Eight enforcement cases were closed without the collection of a civil penalty or the issuance of a compliance order. Three of these closures were affected by letters warning the operator of possible future enforcement action for further violations of the regulations (see Appendix D). Nine cases remained active at the end of 1980.

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LIQUID PIPELINE FAILURE INVESTIGATIONS

Significant liquid pipeline failures are investigated by MTB to ascertain whether the Federal safety standards are being properly complied with and to determine if additional regulatory action should be initiated.

During 1980 there occurred two such accidents. On December 1, 1980, a 10-inch line operated by Four Corners Pipeline Company ruptured in a Long Beach, California, neighborhood. While naphtha was being pumped from the Marlex refinery to another refinery, it gushed to the surface, came down the street and was ignited, destroying nine homes and burning two persons seriously.

On December 9 and 10, 1980, a representative of the DOT's pipeline safety Western Regional Office conducted an investigation in relation to the rupture. The results were as follows:

1. The line is subject to DOT's safety regulatory jurisdiction under the Hazardous Liquid Pipeline Safety Act of 1979 (Title II of Pub. L. 96-129, November 30, 1979), as an intrastate facility.
2. At present the Federal liquid pipeline safety regulations issued and enforced by DOT (49 CFR 195) do not apply to intrastate facilities.
3. Several probable violations were noted if the line were subject to 49 CFR 195.
4. It is advised that operation of the line be reviewed with the objective of eliminating possible hazard by providing for the following:
   a. Adequate relief facilities on the pipeline;
   b. Shutdown devices for public over-pressure protection;
   c. Adequate communications between operating personnel;
   d. Review of maximum allowable operating pressure and maximum operating pressure;
   e. Maintenance of over-pressure and relief facilities.
7. Section 209(b) of the Hazardous Liquid Pipeline Safety Act of 1979 states the responsibilities of the Secretary of Transportation if he finds a liquid pipeline facility to be hazardous to life or property, whether or not such a facility is subject to 49 CFR regulations.

On March 6, 1980, at 3:36 p.m., EST, Colonial Pipeline experienced two simultaneous breaks in its 32-inch refined products line in Northern Virginia. One break was located at Highway 234 in Prince William County, 1.06 miles south of Colonial's Bull Run, Virginia, pump station. The second break was located near Highway 611 in Orange County, Virginia, near Colonial's Locust Grove station. The Bull Run break resulted in spilling 8,000 barrels of kerosene, of which 6,130 barrels were recovered. No deaths, fires, or personal injuries resulted. In both instances, spilled product flowed into waterways but was ultimately contained and recovered. Both breaks caused a certain amount of damage to the environment, particularly to fish, small wildlife, and vegetation. There was also an interruption of the normal water supply to the City of Fredericksburg.

The pipe failure in the cased crossing of Highway 234 near Manassas, VA, was caused by the approximately 4-inch diameter corroded area in the carrier's pipe.

The reason for the badly corroded area on the carrier pipe was due to the electrical short between the carrier pipe and casing combined with a loss of coating on the carrier pipe and water in the annular space between carrier pipe and casing that provided an electrical conducting medium.

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LIQUID PIPELINE RESEARCH AND DEVELOPMENT PROGRAM

The Materials Transportation Bureau's research and development program provides technical support for development, modification, and interpretation of the liquid pipeline safety regulations and for enforcement activities. Project Highlights for 1980 include:

Damage and Confinement in Offshore Pipelines

The California Institute of Technology began a study under the Department's University Research Program to determine the effect of damage, particularly buckling, on offshore pipelines. Progress is being monitored by MTB technical staff.

Analysis of Design Criteria for Alyeska Pipeline Repairs

Under agreement with MTB, the NBS finalized a report on the design criteria for repair sleeves installed on failed sections of pipe of the Trans-Alaska crude oil pipeline. MTB is continuing to study these repairs to assure that they are structurally sound and in conformance with 49 CFR Part 195 and other standards. Repaired sections of the Trans-Alaska oil pipeline at Mileposts 166 and 734 have been monitored during the year and a half since the originally noted breaks, and no problems have occurred. Corings from holes drilled in 1980 have confirmed the hypothesis for the 1979 failures as thawed permafrozen soil and ice. Subsurface studies are continuing in other possibly susceptible locations to assure pipeline stability.

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OUTSTANDING PROBLEMS

Certain problem areas persist as impediments to a fully effective Federal pipeline safety program.

Consensus Standards

The Federal standards incorporate by reference many documents commonly called "consensus standards" that are prepared by non-government organizations. The references to non-government documents simplify the task of regulating highly technical subjects, but they present problems for MTB and the regulated industry. Often the documents are not written in regulatory language, making them difficult to enforce, and later-published editions cannot be used by the industry until MTB approves the practice by referencing those later editions.

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APPENDIX A

Amendments to 49 CFR Part 192

1. Joining of Plastic Pipe.
2. Separately Protected Service Lines.
3. Liquefied Natural Gas Facilities.
4. Repair of Transmission Lines.

DEPARTMENT OF TRANSPORTATION
Research and Special Programs Administration
Materials Transportation Bureau
49 CFR Part 192
(Amdt. 192-34B, Docket No. PS-54)
Transportation of Natural and Other Gas by Pipeline; Joining of Plastic Pipe

AGENCY: Materials Transportation Bureau (MTB).

ACTION: Final rule.

SUMMARY: This final rule permits a burst test in accordance with Paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or Paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517 in qualifying joining procedures for thermosetting plastic pipe. In addition, the rules for qualifying joining personnel are clarified by permitting any one of three tests required to qualify a specific joining procedure to be used to qualify persons to make joints under that procedure.

EFFECTIVE DATE: January 2, 1981. Since this final rule clarifies existing rules and does not add to the regulatory burden, no further public proceeding is necessary, and it may become effective upon publication in the Federal Register.

FOR FURTHER INFORMATION CONTACT:
Paul Cory (202) 426-2082.

SUPPLEMENTARY INFORMATION: A final rule was published on July 23, 1979, (Amdt. 192-34, 44 FR 42069) and revisions thereto on February 14, 1980, (Amdt. 192-34A, 45 FR 9931), establishing tests for qualifying procedures and personnel to make all types of joints in plastic pipelines used in transportation of natural and other gas by pipeline.

Section 192.283(a) sets forth three test methods for qualifying joining procedures that use heat fusion, solvent cement, or adhesive techniques. It was MTB's intent that any one of these three methods be permitted to qualify joining personnel. In the preamble to Amdt. 192-34A in discussing Qualifying Persons to Make Joints, MTB stated: "Convincing arguments were presented for using as a qualifying test any of the test methods permitted under § 192.283(a) for qualifying joining procedures." To carry out this intent, the final wording of § 192.285(b) (2) (i) reads, "tested under § 192.283." At least two operators, Atlanta Gas Light Company and Mountain Fuel Supply Company, have pointed out that this wording indicates that each of the three tests under § 192.283(a) must be employed, not just one. This final rule clarifies § 192.285(b) (2) (i) to eliminate this potential point of misunderstanding.

The wording of § 192.283(a) requires all plastic pipe to be burst tested under Paragraph 8.6 or Paragraph 8.7 of ASTM D2513. However, ASTM D2513 specifically applies to thermoplastic piping materials and does not adequately test thermosetting resin plastic pipe. The comparable appropriate tests for use with thermosetting resin pipe are set forth in Paragraph 8.5 or Paragraph 8.9 of ASTM D2517. This distinction and the need to establish a valid test for thermosetting pipe were inadvertently omitted from Amdt. 34A. This final rule amends § 192.283(a) by adding the necessary reference for thermosetting pipe.

In consideration of the foregoing Part 192 of Title 49 of the Code of Federal Regulations is amended as follows:

1. Section 192.283(a) (1) is revised to read as follows:

§ 192.283 Plastic pipe; qualifying joining procedures.

(a) * * *

(1) The burst test requirements of—

(i) In the case of thermoplastic pipe, Paragraph 8.6 (Sustained Pressure Test) or Paragraph 8.7 (Minimum Hydrostatic Burst Pressure) of ASTM D2513; or

(ii) In the case of thermosetting plastic pipe, Paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or Paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517;

* * * * *

2. Section 192.285(b)(2)(i) is amended to read as follows:

§ 192.285 Plastic pipe; qualifying persons to make joints.

(b) * * *

(2) * * *

(i) Tested under any one of the test methods listed under § 192.283(a) applicable to the type of joint and material being tested;

* * * * *

[49 USC 1672; 42 USC 1804 with regard to offshore gathering lines; 49 CFR 1.53 and Appendix A of Part 1]

Issued in Washington, D.C., on December 22, 1980.

L. D. Santman,

Director, Materials Transportation Bureau

[FR Doc. 80-40474 Filed 12-31-80; 8:45 am]
Billing Code 4910-80-M

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Research and Special Programs Administration
Materials Transportation Bureau
49 CFR Part 192
(Amdt. 192-35A, Docket No. PS-52)

Transportation of Natural and Other Gas by Pipeline; Separately Protected Service Lines

AGENCY: Materials Transportation Bureau (MTB), DOT.

ACTION: Final rule.

SUMMARY: A final rule was published (Amdt. 192-35; 44 FR 75384, December 20, 1979) establishing requirements for testing, on a sampling basis, cathodic protection on short sections of transmission lines. That final rule unintentionally altered the requirement for testing cathodic protection on separately protected service lines. This amendment reinstates the original requirement, which allowed separately protected service lines, regardless of their length, to be tested on a sampling basis if annual tests are impractical.

EFFECTIVE DATE: April 7, 1980.

FOR FURTHER INFORMATION CONTACT:

L. M. Furrow on (202) 426-2392.

SUPPLEMENTARY INFORMATION: On August 28, 1978, MTB issued a notice of proposed rulemaking to amend the cathodic protection monitoring requirements of § 192.465(a) (43 FR 39401, September 5, 1978). The purpose of the notice was to invite comments on a proposal to allow transmission line sections that are impractical to monitor annually to be monitored by the sampling procedure applicable to service lines and mains.

The language of the proposal read: "However, if tests at those intervals are impractical for separately protected service lines or short sections of protected mains and transmission lines, not in excess of 100 feet, these pipelines may be surveyed on a sampling basis." (The proposal merely would have added the words "and transmission lines," immediately after the word "mains" in the original rule.) In Amendment 192-35, this proposed language was changed to read, "However, if tests at those intervals are impractical for separately protected sections of pipeline not in excess of 100 feet, these pipeline sections may be surveyed on a sampling basis." This language change was intended merely to clarify that the phrase "not in excess of 100 feet" in the original rule applied to service lines as well as mains. The change appeared justified by the plain meaning of the original rule, and it did not appear that any contrary interpretation had been made.

Following adoption of Amendment 192-35, MTB has received letters and petitions from several interested persons pointing out that ever since the issuance of section 192.465(a) (Docket No. OPS-5, 36 FR 12302, June 30, 1971), the gas industry has been permitted to monitor separately protected service lines that are impractical to monitor annually, on a sampling basis, regardless of their length. Various arguments (technical, legal, and cost/benefit) have been advanced to support the position that the 100-foot limitation in the original rule was intended only to define "short sections of protected mains" and not to modify the term "service lines."

MTB has evaluated these arguments by checking the record of Docket No. OPS-5 and consulting knowledgeable field enforcement personnel. Both the record and enforcement practices are consistent with the view that until issuance of Amendment 192-35, separately protected service lines have been eligible for monitoring a sampling basis, regardless of length. It also appears that Departmental training material provided to industry participants indicates that separately protected service lines were not considered subject to the 100-foot limitation. As a result, because Amendment 192-35 was not intended to modify the existing rule with regard to service lines, MTB is hereby amending section 192.465(a) as set forth below to eliminate any further misunderstanding about application of the 100-foot limitation to separately protected service lines.

In consideration of the foregoing section 192.465(a) is revised to read as follows:

§ 192.465 External corrosion control: monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of section 192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet, or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

* * * * *

[49 USC 1672; 49 CFR 1.53 and Appendix A of Part 1]

Issued in Washington, D.C., on April 1, 1980.

L. D. Santman,

Director, Materials Transportation Bureau

[FR Doc. 80-10193 Filed 4-4-80; 8:45 am]
Billing Code 4910-80-M

Research and Special Programs Administration
49 CFR Part 193
(Amdt. 193-1, Docket OPSO-46)
Liquefied Natural Gas Facilities; Reconsideration of Safety Standards for Siting, Design, and Construction

AGENCY: Materials Transportation Bureau (MTB), DOT.

ACTION: Final rule.

SUMMARY: Final rules were issued on the siting, design, and construction of Liquefied Natural Gas (LNG) facilities on January 30, 1980. In response to petitions for reconsideration, MTB is amending several sections of the final rules. These amendments are: (1) To clarify that any subsequent changes in "existing LNG facilities," as defined by the Pipeline Safety Act of 1979, including expansion of capacity, if made pursuant to an application for approval filed before March 1, 1978, would not be subject to Part 193 siting requirements; (2) to provide that the Director will respond within 90 days to a petition for finding or approval unless the petitioner is otherwise notified; (3) to exclude "pipeline facilities" of the operator from thermal radiation protection requirements; (4) to clarify the vaporization rate for a design spill from a transfer line that penetrates an LNG storage tank below its liquid level; (5) to require the Director's approval for siting LNG storage tanks in certain areas of high seismic activity; (6) to modify the criteria for identification of a high seismic area, where the Director's approval for siting an LNG storage tank is required; (7) to make only impounding systems for LNG storage tanks subject to requirements relating to penetration by wind borne missiles; (8) to establish a 200 mph wind speed as an upper limit in designing for wind forces; (9) to clarify that any ultraviolet decay of insulation must not be detrimental to the insulation; (10) to clarify that only valves for use in controllable emergencies must have powered local and remote operating capabilities; (11) to clarify the dimensions required for dikes; and (12) to provide that only LNG storage tanks must meet the protection requirements for shared impoundment. MTB has also amended the scope of Part 193 to be consistent with the siting provisions of the memorandum of understanding with the U.S. Coast Guard, amended the definition of "LNG facility" to be consistent with the definition of this term in the Pipeline Safety Act of 1979; and changed the title and scope of Subpart B to refer to "Siting Requirements."

EFFECTIVE DATES: Because this document clarifies or relaxes requirements currently in effect, it is advantageous for industry to begin compliance without delay. Therefore, the final rules are effective August 28, 1980. In addition, the recordkeeping requirements of §§ 193.2119 and 193.2329, and any recordkeeping requirements incorporated by reference in Part 193, adopted as final rules in 45 FR 9184, become effective September 29, 1980.

FOR FURTHER INFORMATION CONTACT:

Walter Dennis (202) 426-2392.

SUPPLEMENTARY INFORMATION: Final rules were published February 11, 1980, establishing standards for the siting, design, and construction of LNG facilities (45 FR 9184) in a new Part 193. These standards were issued under the Natural Gas Pipeline Safety Act of 1968, as amended by Title I of the Pipeline Safety Act of 1979 (49 U.S.C. 1671 et seq.) (the Act).

Earlier regulation actions preceding issuance of the final rules were: (1) An advance notice of proposed rulemaking (ANPRM) (42 FR 20776, April 21, 1977), (2) A notice of proposed rulemaking (NPRM) (44 FR 8142, February 8, 1979, (3) A conference with Western LNG Terminal Associates (Western) *et al.*, held in Washington, DC, on April 24 and 25, 1979, and (4) a meeting of the Technical Pipeline Safety Standards Committee (TPSSC) held in Cambridge, Massachusetts, on June 12-15, 1979.

After the final rules were issued, the American Gas Association (AGA), Interstate Natural Gas Association of America (INGAA), and Western filed petitions for reconsideration of certain provisions in the new standards under 49 CFR Part 106. In aggregate, the petitions apply to 22 specific provisions, appearing in 16 separate sections of Part 193. Also, Western requests reconsideration of the final rules on the basis of several procedural issues.

Following receipt of the petitions for reconsideration, in accord with MTB procedures in 49 CFR 106.37, MTB sought comments on the petitions from several interested parties. Persons who commented on specific features of the petitions, either solicited or unsolicited, were:

Ted Stevens, U.S. Senator from Alaska (Stevens);
Harold T. Johnson, U.S. Representative from California (Johnson);

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Robert B. Duncan, U.S. Representative from Oregon (Duncan);
The State of Alaska (Alaska);
Hollister Ranch Owners Association (Hollister);
Santa Barbara Citizens for Environmental Defense (Citizens);
Bixby Ranch (Bixby);
Sierra Club (Sierra);
James F. Devine, Acting Assistant Director of Engineering Geology, U.S. Geological Survey (Devine);
Federal Energy Regulatory Commission Staff (FERC); and
Dr. Nathan M. Newmark, Consulting Engineering Services, (expert witness on seismic design for Western) (Newmark).

Except for FERC, which addressed all aspects of the petitions, the comments focused mainly on the prohibition under § 193.2061(f) against siting LNG facilities in certain areas of high seismic activity.

Both the petitioners and some commenters reference testimony given at the conference with Western *et al* in April, 1979, by expert witnesses, Newmark:

Dr. Robert D. Hanson, Chairman,
Department of Civil Engineering,
University of Michigan, (Hanson); and
Dr. Richard Jahns, Dean, School of Earth Sciences,
Stanford University (Jahns).

The disposition of the petitions together with the reasons for granting or denying aspects of the petitions or the basis for other decisions and the resulting amended rules follow:

General

In Part III of its petition (Parts I & II are discussed hereafter), Western asks that MTB reconsider several procedural issues and objections relating to the proceeding. While some of these matters have already been specifically answered by MTB, Western raises them to preserve its future rights in the event of court action. A brief response to each of these issues and objections follows.

A. Analysis or Evaluation

Western argues that a "Regulatory Analysis" instead of an "Evaluation" should have been prepared because the final rules will result in substantial compliance costs for the LNG industry and perhaps significantly impact consumer costs. Under the applicable Departmental procedures (43 FR 9582, March 8, 1978), a Regulatory Analysis is required for regulations that could result in a major effect on the general economy in terms of costs, consumer prices, or production, or could result in a major increase in costs or prices for individual industries, levels of government, or geographic regions. An Evaluation is required for all other regulations. Using figures from the Final Evaluation, the total annualized costs of the final rules to build from 6 to 64 facilities range from $8.4 million to $17.4 million yearly over a 20-year period. Even though Western characterizes these costs as "substantial," by any reasonable measure (there is none given in the procedures) they are not high enough to cause a "major effect" either on the general economy or the regulated LNG industry. Therefore, MTB's preparation of an Evaluation was proper under the Departmental procedures.

B. Conclusions of the Evaluation

The Final Evaluation concluded that eight sections in Part 193 have costs that exceed benefits. Western argues that adoption of these sections as final rules disregards the cost/benefit conclusions and makes the rules unreasonable and impracticable. This argument is equivalent to saying that MTB may not adopt a rule unless it is proven to be cost beneficial. Neither Executive Order 12044 nor the Departmental procedures support such a conclusion. There are many factors to be considered in deciding whether a rule should be adopted, of which compliance costs in comparison to quantifiable benefits is but one. Other factors include the need for the rule, the safety objectives to be attained, the effectiveness of the rule, the burdens it imposes and its technical feasibility. Certainly no one of these factors should be determinative of reasonableness as Western suggests. Furthermore, MTB did not disregard the cost/benefit conclusions. A discussion of the need for the rules in light of the conclusions is included in the preamble to the final rule for each affected section.

C. Sufficiency of Economic Data

Western asserts that the data regarding the economic impacts of the final rules were insufficient for MTB to properly analyze the economic effects or consider alternatives. Although this assertion is made without foundation or examples of deficiencies, it is important to note that Departmental procedures do not require that any particular methodology be used in making an economic analysis. The use of a particular methodology, including the data for analysis, is left to the discretion of the agency concerned, subject of course, to public scrutiny at the draft stage, MTB notes that Western did not raise this point when the Draft Evaluation was available for comment.

D. Advisory Committee Review

Western charges that MTB's handling of the advisory committee review of the proposed rules as required by section 4 of the Act was irregular in several respects: (1) The Committee lacked full membership, (2) The Committee's views were obtained, in part, by letter ballot rather than through direct discussion, and (3) MTB did not submit to the Committee for consideration proposed rules that, after their initial submission to the Committee, were later modified in a manner not approved by the Committee. MTB finds nothing in either section 4 of the Act or the Committee charter that would lend merit to any of Western's charges. The charter specifically authorizes Committee action by a majority of current members present and by letter ballot in

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lieu of discussion. The full intent of section 4 of the Act was met when MTB submitted all the proposed LNG rules to the Committee for review, and the Committee openly considered them at a 4-day meeting (June 12-15, 1979). Section 4 specifically permits MTB to make a final decision on proposed rules, after considering Committee views and explaining why any views are not adopted. After an initial review by the Committee, to return to the Committee for further comment in the mandatory sense suggested by Western would be equivalent to unlawfully relinquishing the final decision-making role to the Committee, since MTB could, under those conditions, never independently make a final rule.

E. Statutory Decisionmaking Factors

Western states that the final rules are defective because the record contains no evidence that MTB took into consideration in prescribing the rules the several factors listed in section 6(d) of the Act, particularly "the need to encourage remote siting." To the contrary, the final rules contain numerous specific provisions relating to the section 6(d) factors. For example, remote siting is an option available to operators in complying with the exclusion zones required by sections 193.2057 and 193.2059. Also, in this regard, the preamble to the April 21, 1977, advance notice discussed the need for safety standards based on different population densities, and the Evaluation analyzes the remote siting alternative. The safety advantages of "remote siting" are essentially obtained by compliance with the exclusion zone provisions, without incurring such potential drawbacks as poor positioning relative to existing pipelines, gas markets, or navigational needs.

F. Advisory Committee Advice

Under section 4 of the Act, MTB must give reasons for rejecting the views of the advisory committee upon a proposed rule. Western makes a general allegation that MTB has failed to meet this requirement with regard to proposed rules for which the Committee issued an unfavorable report. This is incorrect. For the most part, MTB adopted the views of the Committee in issuing the final rules and thus, there was no need to explain its position vis-a-vis that of the Committee. Where Committee views were not adopted, the reasons for rejection were given in the preamble to the final rules.

§ 193.2005 Applicability.

The purpose of this section is to distinguish between new and existing LNG facilities regarding the application of Part 193 standards affecting siting, design, or construction (including installation, initial inspection, or initial testing). In Part II of its petition, Western argues that in section 193.2005(b)(1), MTB has acted contrary to section 6(c)(1) of the Act by imposing new siting standards on existing LNG facilities.

Section 6(c)(1) of the Act forbids the application of new Federal LNG safety standards affecting design, location, installation, construction, initial inspection, or initial testing to an "existing LNG facility," although standards which do not affect location may under certain conditions (relating to compatibility or practicability) be applied to any "replacement component or part thereof" put in service after the standards are issued. The term "existing LNG facility" is defined by section 2(14) of the Act as any LNG facility for which an application for approval of the siting, construction, or operation was filed before March 1, 1978, with a particular Federal, State or local agency. Standards for the siting, design, and construction of any "new LNG facility" are authorized by section 6(a) of the Act; and a "new LNG facility" means any LNG facility other than an existing LNG facility.

Excepted from the meaning of "existing LNG facility" is any facility the construction of which begins on or after November 30, 1979, where the construction is pursuant to an approval initially applied for on or after March 1, 1978, in the form of an amendment to a pre-March 1, 1978, application. Under the Act, such a facility falls within the meaning of a "new LNG facility," and is therefore subject to siting, design, and construction standards for new LNG facilities authorized by section 6(a) of the Act. The intent of this exception can be illustrated using the applications filed with the Federal Energy Regulatory Commission (FERC) and its predecessor organization seeking approval for the construction and operation of an LNG facility on Staten Island, New York.

- November 1973—Application filed for a Certificate of Public Convenience and Necessity to construct and operate an LNG facility at Staten Island Docketed as CP 74-122.
- March 1979—Amendment to CP 74-122 filed seeking authorization to operate the Staten Island facility as a peak shaving facility (using one of two 900,000 gallon storage tanks) and to construct and operate a liquefaction unit at the facility.
- February 1960—Amendment to CP 74-122 filed seeking authorization to use both of the facilities' 900,000 gallon storage tanks and existing vaporization and compressor equipment. Amendment also sought approval to construct and operate a liquefaction unit (twice the capacity of the unit filed for in the March 1979 amendment) and more vaporization units.

None of the above filings have yet been the subject of approval of FERC.

In applying the Act's definitions to the facilities subject to approval under CP 74-122, only those facilities for which approval of the siting, construction, or operation was applied for in the November 1973 filing would be considered "existing LNG facilities." In accordance with the Act's exception to the definition of "existing LNG facility," the facilities for which initial approval of the siting and construction was applied for in the March 1979 and February 1980 filed amendments would be considered "new LNG

facilities," and therefore subject to the siting, design, and construction standards issued under section 6(a) of the Act.

Section 193.2005 (b)(1) provides that if an existing LNG storage tank is relocated or its storage capacity is increased through replacement or significant alteration, the relocation tank, replacement tank, or significantly altered tank must meet the siting requirements of Part 193. Western argues that this provision is unauthorized because section 6(c)(1) of the Act forbids regulation of the siting of an existing LNG facility, including "any subsequent activity" that occurs with respect to the facility. Western supports this argument by referring to the plain meaning of section 6(c)(1) and its express prohibition against applying standards that affect location to any replacement of an existing facility, and by a somewhat liberal reading of the legislative history. From its reading of legislative history, Western infers that Congress did not intend to subject any reconstruction of an existing LNG facility to siting standards.

MTB does not dispute the basic premise of Western's argument, that nothing about an existing LNG facility may be regulated from a siting standpoint. In adopting this policy, Congress obviously recognized the virtual impracticability of retroactively applying new siting standards to facilities already built or under construction and, as indicated by the legislative history, the unfairness and delays that would result if siting standards were applied to facilities for which applications for approval had been pending since at least before March 1, 1978. Congress was also concerned that these existing facilities not be hindered from making needed replacements, but that the replacements be safe. Therefore, under section 6(c)(1)(B) Congress granted limited regulatory authority over the design and construction of replacements to existing LNG facilities, but specifically disallowed regulation of replacements to existing LNG facilities from a siting standpoint. We do believe, however, that Western has neglected to give recognition to the fact that the Act's definitions of "LNG facility," "existing LNG facility," and "new LNG facility" presuppose the possibility of a system of LNG facilities functioning as a unit, being composed of new and existing LNG facilities and also the possibility that certain relocation, reconstruction, or modification of an existing LNG facility makes the resulting facility a "new LNG facility."

For Western's argument to hold, relocated or enlarged facilities must be considered "existing LNG facilities" under section 6(c)(1). The relocated or enlarged facility would, under the statutory definition of "existing LNG facility," have to be one for which approval of the siting, construction, or operation was applied for before March 1, 1978. While we admit the possibility that a pre-March 1, 1978, application might have sought approval of subsequent relocation or enlargement activity, where it did not, such relocation or enlargement activity would need be the subject of an initial application for approval filed on or after March 1, 1978. As such, in applying the exception clause to the Act's definition of "existing LNG facility" (discussed earlier), the resulting relocated or enlarged facility would be a "new LNG facility" for which siting standards are authorized.

This reasoning, relied on in adopting § 193.2005(b)(1), is further supported by a statement from H. Rep. No. 96-201, Part 1, 96th Cong., 1st session (1979) at Page 24. At this point in its discussion of the authority to regulate existing LNG facilities, the House Committee on Interstate and foreign Commerce says:

> Standards for existing facilities are to be directed toward operational procedures only, including considerations such as the number of operators and security measures. They (standards for existing facilities) should not apply to any reconstruction or substantial modification of an existing LNG facility, which would result in a substantial increase in capacity. Such reconstruction or modification would render that facility subject to the rules promulgated for new LNG facilities, but only with respect to such reconstruction or modification. The original portion of the facility would remain "existing" but the reconstructed, modified or expanded portion would be "new".

This statement of the legislative history shows that any reconstruction activity that goes beyond mere replacement-in-kind of an existing facility to the extent that capacity is increased makes the resulting facility a new LNG facility. While the Committee continues its discussion by giving as an example of a new facility the construction of a third storage tank at a site where two had existed previously, it is important to note that the same result could be achieved (although impractically) by tearing down the original two tanks and rebuilding them to larger sizes.

Although we do not agree with Western that an existing facility remains an existing facility for purposes of section 6(c)(1) regardless of the changes it may undergo, we do concede that any subsequent construction for which approval was applied for before March 1, 1978, (even expansions of capacity) would fall within the meaning of "existing LNG facilty." As currently drafted, § 193.2005(b)(1) does not reflect this distinction; and it is, therefore, changed to apply only to later modifications of existing LNG facilities that are not made pursuant to an original pre-March 1, 1978, application for approval. In addition, the term "replacement" is deleted to avoid the misunderstanding that its meaning includes reconstruction of a storage tank when storage capacity is increased, since such reconstruction would result in a new LNG facility.

§ 193.2007 Definitions. "Failsafe".

AGA and INGAA petitioned to change the definition of "fail-safe" by deleting the word "component" and changing "control device" to "control signal." Thus for example, a "fail-safe" design of a shut-off valve would relate only to loss of power supply or control signal to the valve. In support of the change, both petitioners contend that a fail-safe design to account for a component failure as the present

definition states is not possible. Also, they argue that a component can only assume a preplanned condition and that the definition would require all components to have fail-safe designs. Additionally, INGAA asserts that internal parts of valves cannot be designed or made "fail-safe," and feels that MTB does not intend that "every" component be designed to be fail-safe.

In response to the petitions, FERC comments that since the only substantive requirement for fail-safe design applies to automatic shutoff valves (§ 193.2125), the inclusion of "component" in the fail-safe definition is appropriate.

MTB adopted the present definition of "fail-safe" in response to comments on the NPRM. The broader term "component or component part" in the NPRM was changed to "component or control device" in the final rule. This change was precisely in accordance with the wording recommended by AGA and the TPSSC. INGAA made no recommendation in response to the NPRM.

Concern expressed by the petitioners that all components are required to be fail-safe because of the word "component" in the definition is not warranted. The Part 193 definitions do not by themselves impose any requirements. Rather, they are used to assist in applying the substantive rules of Part 193. The definition of "fail-safe" applies only where fail-safe designs are prescribed for specific components by substantive rules in Part 193 (e.g., § 193.2125). More important, the concept of "fail-safe" in the context of long scientific and engineering understanding is more broadly applicable than to loss of power or control signals. It applies to any malfunction of a part or system for which corrective action is needed in order to maintain safe operation. In the case of a valve subject to § 193.2125, some internal parts would have to have a fail-safe design. For example, a diaphragm actuator may be designed to open or close a valve, as desired, in the event of diaphragm failure. Similarly, the inner valve designs may provide for the valve to close or open in the event of shaft failure from erosion or uncoupling, and instrument controls may be selected to perform appropriately in the event of loss of power, plugged bleed orifices, or linkage failure. A reaction only to loss of power or control signal does not adequately cover the intended fail-safe concept. Therefore, in accordance with the above discussion and FERC's position, the present wording of the definition of "fail-safe" is retained without change.

§ 193.2015 Petitions for finding or approval.

This section sets forth procedures that an operator must follow in requesting the Director of MTB to make findings or grant approvals as authorized by Part 193. To ensure that MTB has adequate time to respond to individual requests, the procedures require that they be submitted at least 90 days before the finding or approval is needed. AGA and INGAA argue that this provision does not commit MTB to act within a definite time frame, and that operators need to know when action will be taken on requests. Although implied by the current rule, MTB agrees that its policy to respond within 90 days should be clearly stated. At the same time, under some circumstances a period longer than 90 days may be needed. Therefore, § 193.2015 is revised to provide that within 90 days after requests are received, operators will be notified either of the action taken on requests or, in cases where the request requires more extensive consideration or where additional data or comments are requested and delay is expected, the date by which MTB anticipates action will be taken.

§ 193.2057(a)(1) Thermal Exclusion Zone (targets).

This section requires safe separation distances between impounding systems and certain targets for purpose of thermal radiation protection, not including targets that an operator uses as LNG facilities. In its petition, INGAA sought to except from the rule, all operator's facilities by changing the term "LNG facility" to "facility." INGAA asserted that pipe storage, maintenance yards, and other non-LNG pipeline facilities should not be subject to the separation distances.

In opposing INGAA's proposal, FERC considered the present wording to be sufficiently flexible, and argues that housing provided by an operator might not be protected from thermal radiation under the suggested change.

MTB feels the term "facility" as proposed by INGAA would open a door for broad exclusions. Concern expressed by FERC regarding operator-owned housing is in general accord with MTB's view. Housing, general office buildings, recreational facilities, or other targets not considered "pipeline facilities" should clearly not be excepted from thermal radiation protection. However, as presently written, the final rule excepts only pipeline facilities that are "LNG facilities." The MTB believes that other pipeline facilities of the operator, since they are of similar risk and purpose, should be excepted. Also, to not except them would create an undue compliance burden in situations where an operator uses common grounds for its LNG and non-LNG pipeline facility operations.

Accordingly, MTB has modified this section to except "pipeline facilities." Thus, a thermal radiation exclusion zone of an LNG facility does not apply with respect to other pipeline facilities of the operator.

§ 193.2057(a)(2) Thermal Exclusion Zone (drainage channels).

Proposals to provide a different method than required by § 193.2057(c)(1) to determine exclusion distances for elongated drainage channels were submitted by each of the petitioners. The proposals suggested that a modified method be used when the length to width ratio of a channel exceeds 4 to more realistically approximate the thermal zone from a burning elongated pool of liquid.

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Each of the petitioners proposed a different method and asserted that the results of its proposed method would be conservative and either technically correct or more representative. None provide substantiation, either in the form of a logically derived detailed derivation or supportive test data. Each method generally produces different results for a given set of conditions.

In determining an exclusion distance "d" under § 193.2057 (b) and (c), INGAA recommended that an impoundment area (A) be calculated using an assumed length (l) of 4 times the width (w). This assumed value would be used to determine "d" from the formula $d = (f)(A)^{0.5}$ and to determine flame length (L) under paragraph (b)(4), in the formula $(L) = 6(A/\pi)^{0.5}$.

AGA also recommends that "d" and (L) would be determined from an assumed value (A). However, AGA would calculate the assumed (A) using an assumed diameter of 4 times surface area divided by the surface perimeter.

While Western recommends use of the same formula proposed by AGA to determine an assumed (A), Western advocates using the assumed (A) to determine an assumed (A) to determine only the flame length (L).

In response to the petitions, FERC essentially supported the method recommended by AGA but proposed an additional provision to assure that impounding spaces associated with such drainage channels meet all other requirements of this section. In argument, FERC expressed only the view that a reduction (in the resulting exclusion distance) would be appropriate for drainage channels.

Using a 10-foot wide channel with varying lengths for comparing results under the § 193.2057 method for calculating exclusion distance ("d") to results under the proposed methods shows the following:

1. For a 40′ × 10′ channel, all methods would result in "d" equaling f(20). In the case of public streets, for example where § 193.2057(d) provides for (f) = (1.1), "d" would be 22 feet.

2. For a 41′ × 10′ channel, "d" would be—
- 22.2 feet under § 193.2057
- 22 feet under INGAA's proposed method
- 29 feet under AGA's proposed method

3. For a 1000′ × 10′ channel "d" would be—
- 110′ under § 193.2057
- 22 feet under INGAA's proposed method
- 35 feet under AGA's proposed method

As can be seen, the INGAA method results in a constant 22-foot exclusion distance no matter what the channel length. While the sudden 7-foot increase in exclusion distance for only a one-foot increase in channel length under the AGA method is not believed to be warranted for safety reasons, MTB seriously questions the adequacy of a 35-foot exclusion distance for a 1000-foot channel length.

The proposed methods of determining an assumed (A) would reduce flame length (L) in amounts proportionate to changes effected in "d". Reductions in (L) would tend to further reduce the safe separation distance between an impoundment system and targets. Whether this reduction would be significant is dependent on other parameters, such as topography, impoundment dimensions, and type of targets.

Incident thermal radiation from any unshielded source point in a flame pattern diminishes with the square of the distance from the source. Energy absorption by the atmosphere further reduces intensity with increasing distance. Therefore, MTB agrees with the implicit view of petitioners that a formula different from the one in § 193.2057(c)(1) would probably be appropriate for an elongated fire field, because incident thermal flux from its more distant source points could be considerably less than incident flux from source points of an equidimensional fire field. This problem was addressed by MTB in the NPRM. However, the proposed point source equation that was to have been applied to the problem received much inconsistent but adverse comment. An alternate methodology was not promulgated in the final rule because (a) response to the NPRM proposal regarding elongated impoundment was generally negative; (b) corroborative test data for elongated impoundment was not known to be available; (c) current thermal radiation data and analysis is imprecise; (d) a need for a specific rule for elongated impoundment was not demonstrated, in that unreasonable exclusion distances resulting from the general method prescribed would be infrequent; and (e) the final rule included in paragraph (c)(2), provisions for the use of new test methods.

The methods recommended by petitioners are not substantiated by either corroborative data or analytical derivation and cannot be logically supported. Also, the methods do not consider the changing intensity of incident flux at equidistant locations along the major and minor axes of a fire field.

The apparent source of the AGA and Western proposal is equation (F-15) in the AGA report IS-3-1. The author, Welker, does not provide either supportive data or derivation for (F-15). Moreover, the formula is proposed only for use in determining flame height by Thomas' correlation, not for use with the incident flux equation for distance $(d) = (f)(A)^{0.5}$. Of greatest importance, the equation (F-15), is clearly proposed for use only if impoundment is "reasonably regular," that is, the ratio is "not more than" 4 to 1. An irregular flame base is discussed on Page C-69 of IS-3-1. Here a 2 to 1 ratio is suggested as the limit for equating areas. Clearly, application of the formula recommended by AGA and Western and supported by FERC does not appear to have a valid basis for use with elongated impoundment having a ratio greater than 4 to 1.

INGAA's proposal appears to be an effort to simplify. Its evident basis is an assumption that two separate fires, in a channel, separated by a space that is 4 channel widths in

length, would not emit thermal radiation to a target on an orthogonal line passing 2 widths away from the end of each fire. Clearly, this is not valid and is the antithesis of safety, particularly in view of the downwind spread of vapor before ignition occurs, potential for multiple fires once a major fire occurs, and the high levels of incident flux permitted under the rule.

Section 193.2057(c)(2) provides for the use of new methods, if adequately substantiated, to determine thermal protective distance. As mentioned above, emissive flux from a channel was a factor in adopting this provision. In view of this feature and the foregoing discussion, a change in the rule is unjustified without appropriate substantiation. Present wording, therefore, is retained as written.

§ 193.2057(b)(4)(i) Measurement of flame length "L".

Only INGAA proposed a change to this section: It would delete the clause defining impoundment area (A) by measurement at the "lowest point along the top inside edge of the dike" and replace it with a clause prescribing that (A) be based only on the volume spilled before spilling is shut off by automatic systems (INGAA uses the term "maximum potential spill" to describe this volume). Such a change results in (A) being the area of a sump, rather than the total area of impounding space available to contain a spill. In this section, area (A) is used to determine (L), a length to account for flame height in the equation $(L) = 6(A/\pi)^{0.5}$. INGAA's only support for its proposal is that use of the larger value for (A), as set forth in the final rule, would tend to discourage "drain-to-sump impoundment design" and that this design "should provide the most favorable safety aspects in case of an LNG spill."

In responding to the INGAA proposal FERC expresses the view that MTB's use of design spills under § 193.2059 for vapor dispersion appears inconsistnt with use of "full tank spills" for the thermal radiation protection. The MTB approach was said to be valid, however, given the greater potential for destruction from a fire close to storage tanks. Commenting that a significant reduction in thermal exclusion zone would result if an exclusion distance were based on sump design, FERC disagreed with INGAA's proposal.

The latest edition (1979) of NFPA 59A provides that thermal radiation protection be based on impoundment of a total spill for targets such as outdoor assembly of 50 or more persons, residences and certain buildings such as penal and educational structures, and "a property line which can be built upon." In the case of such property lines, protective distance would be further increased if a lower level of incident flux (3000 instead of 10,000 BTU/ft.^{2}-hr) could result from a design spill. Each of these NFPA 59A design spill provisions is more stringent than INGAA's proposal.

Foremost for public safety, the paramount safeguard is containment of a spill. If a spill is not confined, it will spread. Vapor dispersion distance will increase and leakage into underground systems may occur, with results similar to those experienced in Cleveland, Ohio.

The Part 193 standards are designed to minimize the possibility of catastrophic failure, However, the possibility cannot be completely eliminated. Because of this possibility, some provisions to mitigate the otherwise very severe consequences of such an event must be retained. For example, standards relating to impoundment design and capacity are predicated on the premise that a catastrophic failure resulting in a full pool of LNG could occur.

Ignition and fire have greater expectancy than vapor dispersion with a large spill. On-site ignition sources are common. A spill that results in vapor dispersion may subsequently be ignited, whereas the opposite is not expectable. Therefore, fire and consequent thermal radiation is more likely to occur as the result of a spill than extensive vapor dispersion.

Sump basins to contain a small spill of flammable liquid or LNG were proposed respectively in the ANPRM and NPRM. In response to comments, this proposed requirement was dropped in the final rules. However, sumps are most effective in controlling fires from small spills and thereby serve to protect the operator's equipment. They are required in impounding systems for water collection purposes under § 193.2171. Capacity for holding small LNG spills can be provided at little or no additional cost. Therefore, the MTB disagrees with INGAA's assertion that prudent operators will be dissuaded from installing sumps unless the prescribed thermal exclusion zone is reduced by permitting a shortened flame length.

Moreover, even given an absolute assurance that a spill size would be small, much of the impoundment space surface area may be wetted from a postulated discharge and flow to a sump basin. This aspect would clearly affect thermal radiation because of fire size in the same way it affects vapor dispersion due to contact surface area and resulting vaporization rate. Thus, even if thermal radiation were to be based on a less-than-catastrophic-failure design spill, use of the sump area, as suggested by INGAA, in determining a safe exclusion distance would produce an inadequate thermal exclusion zone.

The prescribed thermal exclusion zone is not based on a full tank spill, as stated by FERC, since a spill large enough to cover the impounding space floor would result in essentially the same level of thermal radiation as a total spill. Therefore, considering: (a) The likelihood of a fire in the event of a spill; (b) the need to provide for a major or catastrophic spill since it cannot be ruled out; (c) the maximum harm is most likely during the first moments after ignition; and (d) that thermal radiation hazard would be nearly alike for various sizes of spills, § 193.2057(b)(4)(i) is retained in its present form.

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§ 193.2057(d)(6) Limiting values for incident radiant flux on offsite targets.

This section establishes a protective distance between the impounding system for each LNG container or LNG transfer line and the operator's "property line," based on a maximum allowable incident radiant flux at the propety line of 10,000 BTU/ft² hour. The rule is intended to provide a minimum level of protection against thermal radiation for persons who may be near an LNG facility outside its property line, such as on trails or in small recreation areas, for which safe separation distances are not otherwise required by § 195.2057(d).

AGA, INGAA, and Western argue that this requirement is impossible to meet for marine cargo transfer systems, since they must approach and cross an operator's property line at the shoreline. Western is also concerned that area water vaporizers would have to be located further away from an unfrequented beach area than necessary for safety.

As stated in the preamble to the NPRM, MTB adopted the "property line" requirement with some modification from an existing NFPA 59A provision. This requirement and the NFPA provision can be interpreted, however, to refer to the right-of-way for a facility. The term "right-of-way" and not "property line" is used in the definition of "pipeline facility," and, in turn, "LNG facility". Although MTB agrees with the petitioners that a safe distance from a "property line"—using the term in its ordinary sense—cannot be provided for transfer lines that must cross a property line, this impossibility does not exist for distances between such a facility and its right-of-way. For these reasons, § 193.2057(d)(6) is amended by substituting "right-of-way" for "property line."

MTB does not agree with Western that § 193.2057(d)(6) should be further amended to exclude sea water vaporizers. Although some additional piping and pumping costs might result when such vaporizers are located further away from the shoreline (reduced cost for LNG and gas piping could be more than offsetting), there are no overriding compliance considerations as in the case of marine cargo transfer systems, and persons who may be near the facilities should be afforded every reasonable protection.

§ 193.2059(d)(1)(i) Flammable vapor-gas dispersion protection (design spill time criteria).

This paragraph prescribes a design vaporization rate for a spill into an impounding system serving an LNG container or LNG transfer system. The design rate is based on a presumed failure of LNG transfer piping, with additional time for piping that penetrates an LNG storage tank either above or below the liquid level. This vaporization rate is used in determining the design combustible gas dispersion distance.

Each of the petitioners requests that the minimum spill time of 10 minutes not be required for attended cargo transfer operations (transfers between a storage tank and a tank vehicle or marine vessel), arguing that a minimum time is unreasonable on top of the existing requirement in § 193.2439 that transfer piping have an automatic shutdown control system, and the proposed requirement in § 193.1117 (Notice 5; Docket No. OPSO—46) that cargo transfer operations be continuouly monitored by personnel. In addition, for penetrations below the liquid level, all petitioners would eliminate the prescribed additional time for liquid head to equilibrate with that in impoundment (or otherwise reach the penetration level). This additional time for side or bottom penetrations of LNG storage tanks is viewed as unreasonable since § 193.2195(c) requires an internal shut-off valve that would have to have a fail-safe design under § 193.2125, making a prolonged spill from a tank unreasonable to assume. AGA also agrues that as a maximum, the spill time should not be longer than the time required by NFPA-59A.

FERC disagrees with the petitions regarding the 10-minute minimum, stating that in actual practice, a time lapse between emergency notification and shutdown has been demonstrated. Also, FERC points out that § 193.2439(c) permits a reasonable delay in automatic shutdown time between alarm and shutdown to provide for a manual response and adds that any delay in leak detection would further increase shutdown time.

MTB disagrees with petitions to eliminate the 10-minute minimum for cargo transfer systems that are monitored or constantly attended and equipped for shutdown as required by § 193.2439. In furtherance of the concerns raised by FERC that delays in emergency response can occur, the attention of an attendant may be diverted due to other events, he may be slow to respond due to the normally quiescent nature of plant operation, or he may fail to respond effectively because of unfamiliarity with the problem or the trauma of a first time real life LNG emergency. Also, the requirements of § 193.2439 are not a satisfactory safety substitute for the 10-minute minimum design spill, because each sensor or component part would have to function properly in a possibly adverse environment during an emergency to assure a lesser shutdown period. Functional failure of any part of a control system or by an attendant would probably result in dispersion distance extending far beyond the design boundaries, with the attendant potential for severe consequences.

Thus, MTB believes the 10-minute spill time is necessary to account for any variety of conditions that can result in delay of shutdown. Further, the 10-minute time was adopted for consistency with the long standing NFPA 59A requirements for containers with top penetrations, perhaps an even safer situation than presented by cargo transfers.

Similar to the above discussion about § 193.2439, control of vapor dispersion from a tank impoundment should not

be dependent on the operation of an internal valve required by § 193.2195, even though a fail-safe design is prescribed. Unlike top penetrations, where LNG spillage will passively terminate when power is cut off since the boiling liquid will not siphon, the internal valve is not a passive device. It clearly is part of an active control system which requires transmission of a control signal, correct response to the signal, and liquid tight closure of the valve. An active system is inherently less safe, since some positive action is required. If the petitions for removal of equilibration time were granted, the level of stringency would be the same for top, side, and bottom penetrations, yet safe control of vapor dispersion would rely on the operation of an internal valve that cannot be readily inspected or tested. The MTB believes this active system is not an adequate substitute for the current spill provision. Accordingly, the petitions to reduce the level of stringency for side and bottom penetrations to the same level required for top penetrations are denied.

Paragraph 2-2.3.3(c) of 59A provides for a one hour design spill limit for penetration in storage tanks below the liquid level that are defined with internal valves when surveillance and shutdown provisions are acceptable to the authority having jurisdiction. AGA argued that adopting this provision would encourage sub-diking. MTB believes this conditional one hour limit would have little effect, since in those cases where sub-diking could limit the design dispersion distance, appropriate design with a sub-diking arrangement probably could provide for about the same distances whether or not the spill time is limited to one hour. Also, where sub-diking may be encouraged, top penetrations would be discouraged.

MTB believes that encouragement of sub-diking to reduce dispersion distance does not justify an increased risk to the public from the potential dispersion of combustible vapor beyond exclusion zone boundaries if the internal valve fails to operate when needed within a one-hour time period. Therefore this alternate petition is denied, also.

However, some potential for misinterpretation of this requirement in the final rule has become apparent to MTB. Therefore, wording has been changed to clarify that the design spill is considered to continue under the condition of a failed shutoff valve until either liquid equilibration occurs, or until the liquid level in the tank falls below the tank penetration.

§ 193.2061(f) Seismic investigation and design forces (prohibitions).

This section prohibits locating LNG storage tanks where a site investigation shows that very high seismic activity could occur. By precluding the construction of facilities in areas where seismic predictability and design accommodation may be beyond the state of the art, the rule precludes the likelihood of a catastrophic or uncontained spill. If an operator believes that state-of-the-art capability can be demonstrated, an operator may apply to the Director for a waiver of the prohibition. Under this section, highly seismic areas are identified as those:

(1) Within one mile of an estimated differential displacement exceeding 60 inches on a Quaternary fault;

(2) Where estimated design acceleration exceeds 0.8g; or

(3) Where the potential for soil liquefaction cannot be accommodated.

The Issues

There are two basic issues addressed in the petitions for reconsideration. One is the appropriateness of adopting an absolute exclusionary rule like § 193.2061(f) for locating LNG storage tanks. The other is the validity of the fault-at-one-mile criteria to identify a highly seismic area where special government attention is required before a facility may be built.

First Issue; Petitions and Comments

With respect to the first issue, each of the three petitioners argues that outright prohibition should be eliminated in favor of a case-by-case government approval process for siting LNG facilities in identified highly seismic areas. The petitioners argue that prohibition is unreasonble and not in the public interest, considering energy supply and the availability of acceptable sites. AGA and INGAA contend that the regulations should require either compliance with specific conditions, or a demonstration to MTB of design safety by the operator. Knowledge of specific characteristics of the fault is necessary to justify prohibition according to Western. It cites the testimony at the April 1979 conference of Devine, Newmark, Jahns, and Hanson for support. The petitioners do not view the opportunity to seek a waiver from the prohibition as a favorable regulatory framework for new facilities.

In its remarks filed in support of Western, Alaska says the "prohibition" is an "aberational and inconsistent" provision in Part 193, since all other provisions have flexibility for balancing construction costs against the hazards of a location. In view of Alaska's special interest in LNG production and consequently in the availability of marketing terminals, it argues that States should be permitted to balance public health and safety with energy supply and economics.

Stevens and Johnson also advocated reconsideration favoring the petitioner's position against exclusionary seismic standards. Stevens thought that, otherwise, Alaska would be impaired in helping to offset the energy shortage. He also expressed support for Alaska's position on the matter.

Johnson expressed concern that exclusionary seismic provisions might block an LNG plant in California and plant expansion at Western's Point Conception site. He concluded that design which could accommodate the seismic conditions should be available, and that the standards should provide for such judgment, but not reduce safety.

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Western further argues against MTB's statement that commenters failed to substantiate that design can accommodate severe earthquakes by referring to testimony by Newmark and Jahns that dams and other structures have withstood seismic events according to design. Western also says that, according to Newmark, any probable earthquake could be accommodated by design, if there were no cost constraints. Also, Western contends that tests performed in connection with construction of facilities have demonstrated tolerance of severe seismic forces. Regarding MTB's reasoning that prohibition in highly seismic areas is in the public interest because consequences of a severe earthquake are so significant, Western again argues that experts say proper design will preclude adverse consequences, that other redundant safety standards in Part 193 (impoundment and exclusion zones) will protect the public, and that a spill at a remote site would not endanger the public even with total tank failure from an earthquake.

FERC expressed unqualified support of all of MTB's reasons for prohibition. More critically, FERC observed that no experience (even with dams) or testing has shown that LNG storage tanks have tolerance for faulting.

Comments in support of the exclusionary approach were received from Sierra, Bixby, Hollister and Citizens. In commenting on seismic features of the petitions, Sierra urged rejection, saying such changes would emasculate the final rule and are contrary to the public interest. Support of the MTB rationale as well as the content of § 193.2061(f) is expressed. The prohibition is considered to be necessary by Sierra because of the unpredictability of both the faulting, itself, as well as the effects of faulting in a geologically active area. Bixby, Hollister, and Citizens point out that the petitioners continue to ignore the opportunity for seeking a waiver. Since this administrative procedure is readily available, they say modification of the rule is unwarranted. These commenters also underscore Western's admission that the issues are repetitious. Since the rules have been extensively reviewed, they argue, the petitions should be dismissed.

MTB's Disposition of First Issue

Contrary to allegations by Western, other provisions in Part 193, such as requirements for vapor dispersion, thermal radiation, and diking, will not assure public protection if a design seismic event is exceeded. For vapor dispersion, the exclusion zone is sized to accommodate only a piping failure, rather than a catastrophic tank failure. And if diking fails, resulting in an uncontained spill, some of the basic safeguards would be sufficient. Thus, provisions exceeding the requirements of Part 193 would be necessary to assure public safety if seismic overload resulted in catastrophic failure.

Construction tests that demonstrate tolerance for severe seismic forces, as alleged by Western, are not prescribed in the final rules. FERC states there are no such tests. Higher pneumatic and full hydrostatic tests of tanks, proposed in the NPRM, could have demonstrated tolerance for some level of dynamic loading from earthquakes and wind. Other proposed requirements in the ANPRM could have provided information for post evaluation of seismic loads and stress levels. However, these proposed requirements were vigorously opposed by commenters on the ANPRM and were not adopted in the final rules. Nevertheless, there are tests and instrumentation which could demonstrate certain levels of tolerance to earthquake forces. Any reliance on such forms of demonstration should be made as part of a governmental review process.

The statement, attributed by Western to Newmark, that without cost constraint, any probable earthquake could be accommodated by design, appears to contradict Newmark's comment that designs for differential displacements larger than 2 or 3 feet require extensive study and research. Even if accommodation by design for extreme seismic events is possible, the principal concern is uncertainty in predicting the nature and magnitude of the event to be accommodated.

MTB imposed the prohibition under § 193.2061(f) because of the high degree of inherent uncertainty in determining the features of a causative geology and predicting seismic effects, particularly near-field activity; and the dearth of reliable technology for structural designs to accommodate very high seismic action. Comments by Devine and FERC, expert testimony referenced by Bixby and others, and extensive technical literature bear out MTB's concerns relating to geologic and seismic uncertainties. Seismic evaluations done at Point Conception, that show a difference in earthquake energy release of about 30 to 1, emphasize this concern. Newmark; comments by Bixby, Hollister and Citizens on expert testimony; research sponsored by the National Science Foundation; and technical literature point out that more extensive study and research are needed for structural designs to accommodate large differential surface displacements.

Accordingly, in adopting § 193.2061(f), MTB took the view that little could be gained by review and approval by the Director, where adequate technology is likely to be unavailable for making sound technical judgments. However, with respect to the issue of whether outright prohibition is an appropriate regulatory approach, MTB upon reconsideration has determined that modification of the opening clause of § 193.2061(f) to provide for a case-by-case approval would be more appropriate for the following reasons: First, although an approval process is basically only a procedural variation of the prohibition/waiver approach, it provides a more favorable atmosphere within which to seek authority to build a new LNG storage tank. The safety and technical issues and background information to be considered would be the same as in a waiver proceeding, and the matters to be considered can be specified by regulation. Secondly, lead time can be controlled, permitting more timely go/no-go decisions. Thirdly, the specter of the prohibition/waiver process could reflect unfavorably on

an otherwise desirable site having compensating safety features. Finally, considering the nation's energy demands, a case-by-case approval approach would establish a procedural route within the regulations for siting a high risk energy facility without foreclosing in advance any particular site. Thus, § 193.2061(f) has been revised to adopt, in part, the petitioners' request by eliminating the outright prohibition. Rejection or approval of a site relative to the risk created by high seismic activity is made subject to evaluation by the Director, as requested by petitioners.

In responding to a request for approval made under § 193.2061(f), MTB contemplates that the decision process would include submitting the request and supporting data to an ad hoc panel for evaluation and recommendations. This DOT chaired panel would, at a minimum, be composed of individuals representing the State(s) and localities most directly concerned with the proposed site and private and Federal government experts on seismic investigation and design force matters. The panel's report and recommendations would be part of the record of proceedings on the approval application and made available for public comment in advance of the Director's decision.

Second Issue; Petitions and Comments (Exclusion Distance)

With respect to the second issue—whether a one mile distance from a Quaternary fault with 60 or more inches of displacement is an appropriate indicator of a highly seismic area—AGA and INGAA proposed identical changes in § 193.2061(f)(1). Addressing the "one mile separation" aspect of this issue, the word "beneath" would replace the words "within one mile" so as to restrict the identifying criteria to a 60-inch Quaternary differential fault displacement beneath the tank foundation. Elimination of the one mile separation was also proposed by Western. However, Western seeks to modify the language describing the triggering criteria to "60 inches of differential surface displacement of a seismogenic Quaternary fault beneath the tank foundation."

AGA and INGAA contend that the only effect from a fault on a tank that is separated by one mile or any other distance will be from acceleration. Therefore, they assert, only differential fault displacement beneath the tank is applicable to identifying a high seismic risk. Also, AGA together with Western urge deletion of the one mile criterion on the basis that at shoreline sites, proof that faulting is within precribed limits is very difficult. They say that present geophysical methods necessary for offshore investigation cannot provide the required accuracy. Western goes on to comment that the 60 inches of displacement, which it proposed in response to the NPRM, was to have applied at tank location rather than at a one mile distance. Therefore, they assert use of the 60-inch criteria in conjunction with a one mile exclusion distance is unjustified.

In rebuttal to MTB's rationale in the preamble that uncertainties about future faulting and fault splays justify the one mile zone, Western argues that it is invalid to conclude that the area within one mile of a Quaternary fault is unsafe without considering whether the fault is "seismogenic" (could it produce an earthquake). Western contends that further seismic examination and design by experts is a more appropriate regulatory approach. Western also rebuts MTB's statement in the preamble that the final rule was developed with the assistance of Devine and his testimony. With reference to the public hearing in April 1979, they quote Devine as saying that one mile could not cover all unsafe situations and may be either over or under conservative, and that a determination of fault size, ongoing displacement, or surrounding faults and relative displacement on each are necessary. Western concludes that MTB cannot say that Devine is supportive of the final rule and contends that there is no evidence in the record to support the one mile criterion.

Commenting on the issues, Newmark supports the position of the petitioners regarding deletion of the one mile criterion. He proposes language that, except for the amount of displacement, is identical with the language used by AGA and INGAA. The location of the fault displacement is proposed to be changed from "within one mile" to "beneath" the tank foundation. However, no explanation is given for this proposal, or about the uncertainties associated with predicting near-field seismic activity. Newmark merely asserts that "an arbitrary distance to faults regardless of their size and probability of slip is unrealistic and arbitrary."

Misgivings about the one mile criterion were also indicated by Devine in his comments as well as his testimony. However, he points out that a fault trace is not likely to be known with the certainty necessary to assure that the next movement on the fault will not result in differential ground displacement at some distance from the known fault trace, or trace of last movement. Devine feels this factor supports exclusion zones. This factor is not acknowledged by the petitioners.

FERC disagrees with assertion by AGA and INGAA that a fault not directly beneath a component presents only an acceleration problem. FERC cites a number of features that must be acknowledged in earthquake design: (1) Liquefaction, subsidence, and tilting are potential problems regardless of distance from a fault; (2) faulting on a single continuous fault surface is rare; (3) new faulting, particulary when close to existing faults, cannot be ruled out; (4) the effects of shaking, when close to a fault, cannot be reasonably predicted, even when directional effects are ignored; and (5) directional effects, as shown by the 1979 Santa Barbara event, can be substantial.

FERC also takes exception to comments by AGA and Western that lack of accuracy in data on offshore faults would preclude shoreline locations. This, they say, is an invalid reason to eliminate an otherwise valuable restriction

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because if faults could not be discovered by state-of-the-art geotechnical investigation, the site would be acceptable.

Sierra, Bixby, Hollister and Citizens generally support the one-mile exclusionary zone, but indicate that, if anything, a more stringent standard is called for.

Considering the unpredictability of both the potential for faulting and its effects, Sierra feels that the one mile criterion is inadequate. In support of this view, the testimony of Hanson given at the April 1979 MTB conference is referenced. In the testimony he stated that one mile separation from significant faults would not be enough to prevent tanks from being located over a serious fault, and claimed that two or three miles would be a better standard. To exemplify, Sierra alleges that an ever increasing number of faults have been discovered over several square miles at Point Conception, California, as a result of ongoing investigations. The USGS Open File Report No. 80-229 (March 1979, at 16) is referenced for substantiation. The Report is said to conclude that the faults found so far are "structurally inseparable elements of a regional system of severe faults."

Bixby also refers to Hanson's testimony. He is quoted as recommending an exclusionary zone of two to three miles for thrust faults and one mile as a national basis, but adds that this limit may not be adequate for California.

Testimony by Newmark at the April 1979 meeting supporting the exclusionary approach is also quoted by Bixby. Newmark states, "I would support an exclusion principle that barred a facility like this within about a mile of the San Andreas fault." Bixby also relates that Newmark's testimony before FERC in June 1976 states that LNG facilities can be reliably designed within a mile or so of a fault on which earthquake motions of one or two feet might be expected. This testimony, according to Bixby shows that Newmark, while opposing an exclusion zone in his letter supporting the petitioners, has endorsed the concept in testimony.

As a corollary, Bixby, Hollister, and Citizens all point out that the expert sworn testimony and comments in the docket contradict Western's allegation that there is no evidence in the record to support the one mile criterion.

Petitions and Comments; (Differential Displacement)

The magnitude of estimated differential Quaternary displacement is the other aspect of the second issue that must be considered. Although petitioners did not request a change in the 60 inches or more magnitude, it becomes a matter for reconsideration because of the petitions to establish displacement criteria for faults at a point beneath the tank, the associated comments on the appropriate magnitude of a fault displacement beneath the tank, and the need for changes recognized by MTB as a result of the comments.

Western asserts that the prescribed 60 inches of differential displacement over two million years is not valid criteria for discriminating against an area one mile around a fault without evaluating the potential effects at the tank site. As mentioned, Western acknowedges that this magnitude of displacement was its own proposal for a final rule made in response to the NPRM. However, Western states correctly that it was to be applied in connection with a fault location beneath the tank. This criteria, it alleges, is in accordance with testimony by Newmark and Jahns. Both men are said to be recognized experts who believe that "varying seismic conditions simply require varying design conditions." However, Western acknowledges that while Newmark speculated that "innovative" design could accommodate displacements in excess of 36 inches, he also stated that current state-of-the-art design, with innovation, can accommodate displacements of only 2 to 3 feet.

Western recalls Jahns' statement that facilities have been designed for 30 feet of displacement. The Palmsdale Dam in Southern California was cited as the example. The criteria of 60 inches of displacement located directly under a tank was therefore viewed by Western as appropriate for triggering special consideration in the installation of large LNG tanks.

Newmark's own comments also address the matter of appropriate limits for displacement directly under an LNG tank. He quotes an excerpt from his testimony at the April 1979 meeting. In part, it says that special designs, not beyond the state-of-the-art, can handle two or three feet. But, it continues, "I would not want to generalize, however, and say that one should permit relative surface motions larger than that under an important structure, or one that is essential to safety." At a following point, he asserts that design for larger displacement is possible, but would require great and extensive study and research.

In his comment, Newmark says that § 193.2061(f)(1) does not accurately reflect his testimony at the April 1979 conference. He proposes revisions in § 193.2061(f)(1) identical with that of the petitioners AGA and INGAA, except that the limit of differential displacement would be 30 inches, rather than 60 inches proposed by the petitioners

Newmark's position, that motions exceeding 2 or 3 feet are beyond the state-of-the-art, is also referenced by Bixby to show that Newmark, who testified as Western's expert, now disagrees with Western's position that up to 60 inches is within the state-of-the-art. In addition, Bixby points out that Newmark earlier testified (El Paso, Alaska LNG Co. Case, Tr. Vol. 157, P. 25946) that LNG facilities could not be reliably designed at, over, or within a mile or so of a fault with one or two feet of expected motion.

With respect to Jahns' statement about the magnitude of displacement allowable for design puposes (30 feet), FERC argues that "no experience, even with dams (which are not comparable with LNG facilities have tolerance for

faulting." Also, use of the word "seismogenic," proposed by Western to describe the Quaternary fault at issue, while appearing inocuous, is considered to be a potentially serious problem by FERC. FERC contends that a fault probably could not be proven to be nonseismogenic. As a result, FERC feels that litigation could be extensive and unresolvable, yet impose excessive burdens on opposing parties. Accordingly, FERC recommends that the term not be used in the standard.

MTB's Disposition of Second Issue

Experts in the field do not uniformly agree on geologic and seismologic terms or their meanings. From the comments and related testimony, conflict about the nature and effects of earthquakes also becomes evident. This is not an unreasonable circumstance, since rapid development is being experienced in these fields. Also, these fields are not precise disciplines and must rely on deductive reasoning as much or more than on direct observation and measurement.

The term "differential Quaternary fault displacement" used by AGA, INGAA, and Newmark, in describing the type of displacement located beneath a tank, clearly is intended to mean differential surface displacement, (i.e., differential displacement of the ground at its interface with the tank foundation). This is made evident by Newmark's interchangeable use of the term "relative surface motions." As used in the final rule, this same term means historic differential movement at the face of a Quaternary fault whether evident by measurement or estimate. Western, in an apparent effort to clarify, uses the term "differential surface displacement of a seismogenic Quaternary fault." Rather than adding clarity, this would introduce possible ambiguity, since unless a fault that is immediately beneath the tank is classified as "seismogenic," construction could apparently proceed without regard to the magnitude of surface displacement that is predicted to occur beneath the tank.

Assertions by AGA and INGAA that ground acceleration will be the only effect from a remote fault are not considered valid. Near-field seismic effects from major events, such as differential surface displacement, subsidence, tilting, vibratory motion, and liquefaction are not well known, as stated by FERC. Also, as Devine explains differential surface displacement may occur at some unpredictable distance from a known fault, or trace of last movement.

The uncertainties in both the faulting and potential effects were also recognized by Sierra, Bixby, Hollister, and Citizens as a justification for the separation. The discussion by Sierra about the results of ongoing, detailed investigation at Point Conception lends weight to Devine's argument.

Hanson's testimony, cited by Bixby, supports the need for separation. And although Newmark expresses opposition to separation (but does not give justification for this view), he has testified in favor of separation as recently as 1976, according to Bixby.

The specter of the uncertainties associated with near-field seismic effects of an earthquake is the principal reason MTB included provisions for separation in the final rule. The San Fernando, California, Earthquake of 1971 (USGS and NOAA preliminary report, 1971) is a good example of some of these uncertainties: Acceleration and other seismic effects far exceeded anticipations for an event of only such moderate size. Rated at 6.6 Richter (the San Francisco 1906 and Alaska 1964 events, in the range of 8.3 Richter radiated a few hundred times more energy), accelerations were the highest ever recorded, measuring 1.0g horizontal and 0.7g vertical with local responses even more dramatic. Evidence suggests that buildings were accelerated vertically at 1.0g (minimum) for about 0.1 seconds. A 20 ton fire truck was moved 6 to 8 feet without showing tire marks, and wine glass stems were broken without lateral movement. Both of these occurrences would require over 1.0g vertical acceleration. A "shattered earth" effect was exhibited in some location, and at one point a rock roadcut appeared to have exploded. The Van Norman Dam (overlooking heavily populated San Fernando Valley) was severely damaged and at the brink of catastrophic failure. Perhaps of greatest significance, some areas of great disturbance were delineated by narrow bands, with only minor damage just beyond, exemplifying the degree of uncertainty in the translation of seismic motions, as discussed by Devine.

MTB agrees with FERC that the argument by AGA and Western about the possible preclusion of shoreline facilities due to offshore investigative limitations is invalid. Investigative measures beyond state-of-the-art techniques are not presumed under the separation provision.

MTB acknowledges that the final rule adopted Western's suggested magnitude of displacement (60 inches) in conjunction with a separation provision. However, this decision is not a valid rationale for deleting the separation provision. The 60-inch criterion clearly exceeds state-of-the-art design for displacement under LNG tanks, and is more appropriate when used in conjunction with a provision for separation from a fault of such magnitude. Western's argument that MTB cannot cite Devine as authority for the final rule is contradicted by Devine's comments on the petitions. MTB together with Devine agree that the criteria are appropriate as used in the final rule.

The criterion of one mile for the separation distance in the final rule is to provide for the unpredictable lateral offset in translation of movement along new faulting (or along a splay or swarm of faults of unknown dimension or location) to a point at the surface under an LNG tank. MTB recognized that a fixed distance could not apply to all conditions. As Devine stated, it could be underconservative in some cases— overconservative in others. (The relevant comments of Devine, and others in this respect, applied to the NPRM criteria which did not prescribe a fixed limit of movement). However, basing the distance on a prescribed amount of dif-

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ferential Quaternary displacement clearly restricted the conditions to a limited range.

As previously stated, the one mile criterion, as used in the final rule, is supported by FERC, Sierra, and Bixby. Although Sierra, Bixby, Hollister, and Citizens indicated that an even greater distance is needed, and expert witness, Hanson, testified (with respect to the NPRM) that 2 or 3 miles would be a better standard, MTB selected one mile as the appropriate distance for a national standard, since in most areas of application, seismic data would not be well known and uncertainties in prediction would be greatest. In such areas, one mile would likely be sufficient to provide suitable attenuation and reduce the likelihood of excessive differential surface displacement occurring under the tank.

Notwithstanding Hanson's view that a distance of 2 or 3 miles would be more appropriate near a significant fault, MTB considers an exclusion distance based on such active locations to be inappropriate for a national standard. However, where more information about the seismic features of such active locations are available, or can be obtained from appropriate investigation by the prudent operator, such information may be sufficient for accurately predicting ground displacement at a tank site. If so, MTB believes the final rule should be changed to permit operators to use this information in judging the safety of a site.

In his testimony, Hanson supported the one mile criterion as a national standard, and according to comments, even Newmark, in other testimony, advocates a one mile distance under certain conditions. Contrary to Western's allegations, response to the NPRM as well as testimony at the April 1979 conference provide ample basis in the record for the one mile criteria, as stated by commenters opposing the petitions. MTB believes the one-mile criteria, when applied in conjunction with specified differential displacement on a Quaternary fault, is appropriate for locations where there is insufficient information to assure a reliable level of predictability about faulting at the tank site. Accordingly, after reconsideration, the one mile zone is retained, but the final rule is revised to narrow its application to areas where reliable prediction of site specific displacement cannot be made. The decision is consistent with petitioner's arguments that a prohibition against construction should not apply without first allowing an opportunity for more detailed investigation of projected effects at a tank site.

MTB has not adopted as a final rule Western's proposal in response to the NPRM (and restated by petitioners in this proceeding) to allow siting of a tank where no more than 60 inches of differential surface displacement is predicted to occur under the tank. Clearly this amount exceeds state-of-the-art design capabilities by a factor of about 2. Even Newmark, Western's expert, made a point of commenting on the petitions in this respect. He argues that the final rules do not reflect his testimony, and follows with an excerpt from his testimony that one should not permit designs for relative surface motions of more than 2 or 3 feet under an important structure. As FERC noted, Western's concept of acceptable displacement derives from a combination of Newmark's 2 or 3 feet for LNG tanks, and Jahns' 30 feet for the Palmsdale, California, dam. This is a contrived view that is not shared by MTB.

Opposing comments extensively debate the 60-inch value, citing expert witness testimony to show that it exceeds limits for accommodation by state-of-the-art designs. Newmark, himself, Western's expert, makes a point of commenting to show that he considers 30 inches to be the appropriate limit. He explains that design for greater displacement requires extensive study and research. And Bixby, citing Newmark's testimony in 1976 before FERC, points out that 30 inches is a quantum step from the one or two feet, within a mile, that he then favored.

Based on comments and testimony, and in consideration of the critical nature of LNG tanks and impoundment, MTB concludes that 30 inches is the outer limit of credible state-of-the-art design, and is including this value in the revised final rule in connection with the allowance made for predictions of displacements at tank sites based on historic data or field examinations.

Use of the term "seismogenic" to describe the character of Quaternary faults to be considered, as recommended by Western, is not adopted for reasons discussed by FERC.

Under the revised rule, where local geologic and seismic conditions are sufficiently well known to predict seismic response immediately beneath a tank, or impoundment for a tank, the need for government review would be dependent on whether differential surface displacement can be reliably predicted to be no more than 30 inches. Construction could proceed on decision by the operator if 30 inches or less of such displacement can be assured.

On the other hand, a differential Quaternary fault displacement exceeding 60 inches within one mile, as currently prescribed, would be the applicable criteria to determine the need for government review if local conditions are not sufficiently well known to reliably predict surface displacement beneath the tank or dike.

Thus, where reliable predictability is possible, surface displacement under the tank or dike becomes the governing criteria. This is important because in areas having the highest seismic activity, a data base for prediction is more likely. Therefore, it serves to help fill the 60.1 inch/1 mile-60-inch/0 mile gap of the current rule, as well as to minimize the likelihood that excessive displacement would occur beneath a tank or dike that has not been accommodated by design. For example, under the revised rule, review for sites more than 1 mile from the San Andreas fault may be required if there is sufficient data base for prediction of displacement at the site, but less than 30 inches relative movement under the tank and dike cannot be reliably assured. Conversely, siting a tank at distances less than a

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mile from a differential Quaternary fault displacement of 60 inches, or more, may be permissible without review, depending on the nature of intervening seismological conditions and data base for predicting displacement at the site.

The prohibition due to soil liquefaction has also been made subject to a petition for approval by the Director, since some of the same overriding benefits of a site, such as remoteness, might apply equally to such conditions.

The revised final rule also sets out the information that an applicant for approval must submit with a petition filed under § 193.2015. This information would include an analysis of the geologic and seismic conditions, design plans with a report showing that the design standards of § 193.2061 would be met under the predicted extreme conditions, and if applicable, any other safety-related siting or design features of the facility not required by Part 193.

§ 193.2063(b)(2) Flooding.

Both AGA and INGAA acknowledge that this section on its own merit is acceptable, as it requires that access to a facility site by offsite personnel be "reasonably assured" in a 100 year flooding event. However, they feel this section when read with the general siting requirements of § 193.2055 implies that access to the site must also be assured for fire fighting equipment along public roads. If this is the case, the petitioners say that in the Gulf Coast area, many access roads would have to be raised 20 feet or more for a distance of about 25 miles.

Section 193.2055 provides as a general requirement that a site must have "ease of access" for handling emergency situations. This general requirement covers many aspects of the means of access to an LNG facility. Section 193.2063(b)(2) deals specifically with access during flooding, and, as such, is governing under those conditions to the extent that access need only be reasonably assured. Therefore, in the example cited by the petitioners, access roads need not be raised where alternative means of access for offsite emergency personnel and equipment are available, such as by boat or helicopter. Hence, this paragraph remains unchanged.

§ 193.2067(a)(3) Wind Forces (penetration by missiles).

Design of containers and other LNG facilities listed in § 193.2051 to withstand penetration by wind borne missiles is required under this paragraph. Its purpose is to assure the integrity of the facility when impacted by objects carried by the wind (particularly a tornado).

Petitions to make only the dikes of impounding systems for LNG storage tanks subject to this requirement were submitted by AGA and INGAA. Western, who proposed a rule on wind borne missiles in response to the NPRM, did not comment. The petitioners argue that the required design is infeasible in most cases, and since all but very large spills would disperse in high winds, only LNG storage tank dikes should be subject to the requirement.

Commenting on the petitions, FERC feels the requirement is vague and design determinations are impossible where missile size and velocity is unknown.

MTB does not agree with petitioners that all damage causing winds would quickly disperse spills and associated vapor, since in the case of tornadoes, high winds quickly move away. Spillage and dispersion would continue.

With respect to the dilemma suggested by FERC, missile size would be a site specific determination. Missile velocity would be calculated using wind forces from wind velocities determined under paragraph (b). Impact loading could be calculated from this information.

However, MTB agrees that design for all of the prescribed facilities to meet this requirement is impractical, if not impossible. A large portion of the facilities would require shielding by protective walls. Also, while an event of this type involves the potential penetration of an LNG storage tank, MTB believes that the continued integrity of the storage tank impoundment is the appropriate safeguard for public protection.

In reconsideration, therefore, the final rule has been reviseed to reflect the views of petitioners. Only the impoundment systems for LNG storage tanks must be capable of withstanding impact from wind borne missiles.

§ 193.2067(b)(2) Wind Forces (design speed).

This section prescribes the bases to be used in determining design wind forces. Its purpose is to assure that containers and other LNG facilities listed in § 193.2051 are designed to withstand the highest wind velocities that can be reasonably expected at the site.

Both AGA and INGAA have petitioned for changes, arguing that a wind design under paragraph (b) (2) (i) based on the prescribed 10^{4} probability of exceedence of the "most critical combination of wind velocity and duration" would result in unrealistically high wind loads. AGA suggests that where probability of tornado occurrence exceeds 10^{4}, the design wind be 200 MPH, the wind speed currently prescribed under paragraph (b) (2) (ii) for use when adequate wind data are unavailable. Where probability of tornado occurrence is less than 10^{4}, the LNG facility would be subject to ANSI-A 58.1, currently prescribed for only small shop fabricated tanks. AGA implies that determining the probability of tornado occurrence is far easier than probability of wind velocity.

AGA would also limit the required wind design to containers and storage tank dikes, but since no explanation for the proposed change was given, this aspect of the petition was not considered. MTB considers the risk of wind damage other than missile penetration to be a serious matter for all the facilities listed in § 193.2051.

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INGAA recommends that the 200 MPH wind speed, now permitted for design where adequate local data are not available to predict some other value, be adopted as an upper limit design standard for all situations.

As a principal argument, both petitioners cite NBS Technical Note 868, "Statistical Analysis of Extreme Winds" to show that a probabilistic determination of wind speed is unrealistic. In providing examples of one probabilistic approach, this report shows wind speeds for various return periods. Based on one type of distribution (Type II, Frechet), and only thirty-seven sample observations, the extreme wind at Corpus Christi, Texas, with an extrapolated return period of 10,000 years is given as 970 MPH.

AGA contends a wind speed this high is physically impossible. INGAA asserts that the 970 MPH speed is unrealistic and would preclude LNG facilities at most coastal locations. It argues that the recommended 200 MPH speed is a reasonable upper limit.

In support of its proposal to use ANSI-A 58.1 for the wind design of containers, AGA states that it contains reasonable steady wind criteria and is referenced by NFPA 59A. As an alternative to referencing ANSI, AGA suggests referencing NFPA 59A which also references ANSI-A 58.1, since experts continuously evaluate NFPA standards.

In commenting on the petitions, FERC states that a change in wording of the final rule is warranted, stating that the 970 MPH wind far exceeds the 200 MPH criteria for sites lacking adequate data.

MTB believes that ANSI-A 58.1 does not provide an adequate wind design level for facilities critical to public safety, such as large LNG facilities. According to NBS 868, ANSI uses only twenty years for a data base which gives unreliable predictability. Also, a mean return period of only fifty years is used (compared to the 10,000 year period) which would result in a high risk level not consistent with other risk criteria in Part 193. Further, the Frechet (Type II) distribution, which is disclaimed by petitioners, is the basis for ANSI criteria. In this case, however, for the ANSI fifty-year return period, predicted extreme wind velocity for Corpus Christi is reduced by one magnitude to 97 MPH.

Therefore, MTB is not persuaded to adopt AGA's proposed use of ANSI-A 58.1 or NFPA 59A as a wind design basis for areas with a low probability of tornado occurrence.

The proposed requirements for wind force design in the NPRM essentially paralleled AGA's petition to use the probability of tornado occurrences as a threshold for applying a design wind speed. Basically, AGA would only change the design wind from the NPRM speed of 250 MPH to 200 MPH, which was adopted in the final rules for use where adequate local wind data is unavailable. In response to the NPRM, many commenters argued that setting a high design wind speed based on the probability of tornado occurrence would be unreasonable since the frequency of that speed would not be considered. They advocated a site specific wind speed based on probability of nonexceedence. AGA was one of these commenters.

In addition to this reason, MTB dropped the NPRM approach because locations not subject to tornadoes might have a relatively high probability of wind speeds caused by other types of storms that greatly exceed wind speeds that produce design loads of building standards. A major gap in design for wind forces and consequent nonuniform levels of protection dependent solely on the likelihood of tornadoes occurring in the area could have resulted.

Accordingly, MTB rejects AGA's recommendation to base design wind forces on a 0.5 percent probability of a tornado occurring within fifty years at a given site.

Section 193.2067 does not require the use of NBS Technical Note 868, "Statistical Analysis of Extreme Winds," for determining the probabilistic wind speed having a return period of 10,000 years. In extrapolating for return periods of 50, 10,000, and 1,000,000 years, the respective velocities with Type II distribution for Corpus Christi are 97, 970, and 9,426 MPH. The corresponding values for Type I distribution are 78, 128, and 172 MPH. These features alone show that either or both the wind data is inadequate or the technique is inappropriate.

Moreover, the NBS report is not intended to provide a standard method for determining extreme winds at any location. Its purpose, clearly stated, is part of an effort to evaluate wind provisions in existing building codes with particular emphasis on the twenty year data base and the Gumbel and Frechet types of data distribution for modeling. In essence, the NBS report concludes:

1. The twenty year data base (using only extreme velocities) is inadequate varying up to several hundred percent for a 1000 year recurrence interval at the same station using different twenty year data sets;

2. Type I and Type II distributions with small tail lengths were both found to fit extratropical as well as tropical storm data; and

3. No single distribution was universally applicable to all data sets.

The citation by petitioners of a single datum in the NBS report to demonstrate the unreliability of one predictive technique does not reflect on the reliability of other techniques that are available. Therefore, the use of this datum by petitioners is not a valid reason to delete the present requirement. There are several techniques that might be appropriate on a site specific basis. The number of years in the data base might be expanded. Alternatively, with a more classical approach, the data base could be expanded by using a broader wind range to correlate speed with return periods by applying the method of least squares to establish best fit equations that are consistent with cycles of natural phenomena. Several analytical techniques can be used to statistically test the degree of reliability of the correlation. Nevertheless, as discussed in the preambles of both the

NPRM and the final rule, such techniques are only of value where adequate wind data are available at a potential LNG site. Where they are not, the final rule sets the design wind speed at 200 MPH.

Based on a review of tornado and other wind data, MTB expects that probabilistic speeds established by using appropriate methods and data will normally fall under 200 MPH. Therefore the 200 MPH wind speed is considered to be a safe upper limit for design wind forces whether or not adequate wind data are available for reliable probabilistic prediction. Consequently, § 193.2067(b) (2) is revised, consistent with INGAA's recommendation, to allow use of the 200 MPH design wind speed without having to make a data search and evaluation to determine if adequate data are available to predict a design speed limit. Still, the predictive alternative is retained for optional use where adequate data are available and reliable predictive techniques are used.

§ 193.2109(c) Insulation.

AGA and INGAA objected to the use of the term "noncombustible" to describe insulation cover. INGAA felt "self-extinguishing" should be used in the final rule, as proposed in the NPRM. AGA preferred "will not support combustion." Both petitioners note that the final rule seems to defy the FTC decision prohibiting "* * * such terms as 'non-burning', 'self-extinguishing', or 'noncombustible' or any term of the like meaning * * *" to describe the burning characteristics of cellular plastics, but, at the same time, recommended similar terminology.

The two different suggestions support the MTB contention, as fully and clearly stated in the preamble, that insulation and the terminology associated with it are presently in a state of flux. As stated in the preamble, MTB will use the term "noncombustible" (NFPA 59A-1979 uses this term in 4-1.5.1) until such time as other agencies or industry develops new criteria. Under the "noncombustible" term in the final rule, material other than cellular plastics must be used as insulation cover.

INGAA also recommended that "where practical" be added to modify the requirement that insulation covering not be subject to "ultraviolet decay." MTB agrees with the contention that there are instances, as on pumps, where it is impractical to use covering materials that are not subject to even a minute degree of decay. However, MTB is adding the word "detrimental" before "ultraviolet" rather than adopting the term "where practical," as the latter term is too indefinite.

§ 193.2123(d) Valves.

INGAA requested that this section be rewritten to apply only to valves that are intended for use during a controllable emergency. Since this suggestion is consistent with the intent of the rule, MTB has made a clarifying change to eliminate any possible inference that a broader application was intended.

§ 193.2151 General design characteristics (impounding systems).

AGA and INGAA recommended that the words "to the maximum extent possible, will prevent" be deleted and replaced by "will minimize the possibility of" in describing the degree to which impoundment design must prevent liquid from escaping. It was claimed the present wording is an absolute design requirement, and one nearly impossible to achieve. MTB feels the suggested wording, "minimize the possibility," could unduly weaken the rule and would be subject to broad interpretation, and, therefore, has not adopted the INGAA suggestion. The final rule provides sufficient design flexibility but requires that design provide for foreseeable events, considering the design spill specified by § 193.2155.

Both petitioners stated the present wording was adopted without the benefit of review and comment by industry, the public, or the TPSSC. This is a curious argument since the questioned wording derives directly from the NPRM.

§ 193.2153(a) Classes of Impounding Systems.

The final rule was changed from the NPRM to allow as much as 24 inches between a dike and the component impounded in a Class 1 impounding system. AGA and INGAA stated the 24-inch space is inadequate to provide a safe working environment for the operator's employees. INGAA recommended a change to 60 inches, whereas AGA proposed more generalized wording to permit distance adequate for maintenance provided the top of the dike is at or above the maximum liquid level of the component served.

FERC felt it would be reasonable to relax the 24-inch limit because of the limited space for personnel and equipment, commenting that only in-tank pumps would be possible.

Misunderstanding about the background, features, and effects of the different classes of impounding systems in Part 193 is made apparent by the comments. The classification of impounding systems derives from NFPA 59A, § 210, 1975 edition. Beginning in the ANPRM and NPRM, two separate classes were proposed for impoundment surrounding a container: A Class 1 configuration (inner face of dike in contact with container) and a Class 2 configuration (dike separated from container). The physical distinction between these two systems results in different safety benefits for each system, and an associated design standard may vary according to the inherent level of safety provided by the class of impoundment.

For example, for low distant diking (Class 2), additional impounding capacity above the required for Class 1 is considered necessary to provide for vapor borne, low friction kinetic flow from a major tank failure, since design configuration of the dike's inner face that will reliably prevent overflow have not yet been developed. With smaller spills, added capacity serves to protect against overflow from splash, jetting, and wave action. When dikes are high, and

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close-in (Class 2), the added capacity provides a factor of safety for uncertainties about formation of vapor bubbles from heat transfer and super heat and their residence time with resulting expansion and reduced density of the mix, coupled with an upward surge of the column of impounded LNG above the level of equilibration due to the kinetics of a rapid release (U-tube effect).

With Class 1 systems, a dike located against the wall of a tank would serve to mitigate the potential of overflow from these causes even in the event of a major tank failure, since contact surface temperature would be lower, and rapid discharge would be restricted. Also, such a configuration, in providing some added support to a tank, would tend to limit the extent of tank failure and resulting size of opening. Accordingly, the required Class 1 impounding capacity is only 110 percent of storage capacity.

In developing the final rules, the NPRM version of Class 1 was modified to permit under Class 1 impoundment up to 24 inches of spacing between a dike's inner face and the tank impounded. This provision was intended for use with specific designs now in use, including protective dikes required under § 193.2155(a) (5) (ii). The purpose of the spacing is to provide a buffer to cushion or prevent excessive loads or shock due to foundation settlement, earthquakes, windloading or other forces from being transmitted between dikes and tanks. Also, it could provide for eccentricities in the configuration of a tank. Certain kinds of infrequent inspection or maintenance could, by design, be accomplished remotely without entry into the annulus by personnel. In addition, the spacing would permit insulation of the inner face of the dike, outer tank surface, or both in order to further minimize vapor dispersion from an impounding system with high close-in dikes that do not have the 150 percent of storage capacity required for Class 2 systems.

Installation of equipment and entry of personnel into the annular space for maintenance duties (except for infrequent occasions when the container is purged out of service) were not considered relevant in prescribing a maximum of 24 inches of separation. The paramount consideration was to balance construction needs against the desire to maintain the benefits intended for a Class 1 system. Also, with this dimension, during operation the effects of natural phenomena, such as ice build up by the migration of moisture in accordance with the laws of natural distribution, together with meterological effects, would mandate either that the annulus be filled with insulation, inert gas or other materials and sealed or covered. Thus, while providing additional safety benefits, this design would restrict spillage to essentially the same degree as a Class 1 system having the dike in contact with the container. Accordingly, MTB concluded that classification under Class 1 impoundment was appropriate.

The INGAA and AGA petitions to reclassify a Class 2 system with more than 24 inches of separation as a Class 1 system would serve only to reduce the minimum impounding capacity for a system with a great uncertainty in overflow potential. Such a change would destroy the principle of prescribing safety factors that are proportionate to the potential for overflow. Considering spacing above 60 inches in small increments, it is evident that logical justification of a Class 2 category and related provisions would be eliminated. Accordingly, the petitions are denied.

§ 193.2161(a) Dikes, general.

Western objects to the prohibition under this section of penetrations in dikes to accommodate piping or any other purposes, and argues that penetrations in LNG storage tank dikes should be permitted to accommodate transfer piping provided the penetrations meet the same structural standards required for dikes (§§ 193.2129 and 193.2155). Western claims that the prohibition imposes high construction costs at a baseload liquefaction plant, since at a multi-tank plant, a single set of pumps can serve all tanks at a plant from a position outside the impoundment area by running LNG transfer piping through the dikes. Western points out the final rule forces the operator to have a separate pumping system for each tank and to either put the loading pumps inside the tank or impoundment. In addition to costs, such placement, Western argues, presents maintenance and handling difficulties especially if high close-in dikes are used to reduce the exclusion zone. Providing additional space for pumps and maintenance within the impoundment, Western argues, might result in more impoundment capacity than necessary under the standards. In addition, Western expressed concern that as a result of increased wetted surface area, the required exclusion distance for thermal radiation and vapor dispersion might have to be increased.

While FERC supports the prohibition of dike penetrations at peak shaving and satellite facilities so as to assure dike integrity, it opposes the prohibition of dike penetrations for transfer lines at multiple tank plants because of the advantages of a central pumping system.

Assured containment of a major LNG spill inside an impounding space is the most crucial consideration in LNG safety. Safety features that rely on impoundment integrity, such as exclusion zones for thermal radiation and vapor dispersion, would not be effective unless a spill is contained. A major spill may result from a variety of causes, and such potential forms a basis for several safety standards, other than § 193.2161. For example, thermal exclusion zones are intended to provide safe distances from burning of a spill that could range in size from one that only covers the floor of the impounding system up to a total tank failure. Also, other standards such as § 193.215(a), § 193.2155(a) thru (c), and § 193.2181, concerning impoundment design and capacity, are clearly intended to assure dike integrity in the event of major tank failure.

Moreover, impoundment is one feature in LNG plant design whose performance capability will usually remain untested after construction unless an event requiring its

complete integrity occurs. Since it is the last "line of defense" against potentially very serious consequences, the benefit of impoundment integrity weighs heavily against the low possibilities of events occurring that could result in a loss of containment.

The prohibition against penetrations is founded on the premise that where dikes are penetrated, a potential avenue is created for a spill of LNG to escape impoundment. There are two basic failure modes to be considered in assessing the acceptability of penetrations: First, there is failure of the penetrating piping in a way that would provide an open conduit for liquid to escape. Second, there is failure of the diking at the point of penetration, or at the point of discontinuity in the dike structure where the sealing structure for the penetration joins the basic diking. These two hypothetical failure modes are "either/or" possibilities, and are, therefore, additive in considering the probability of loss in dike integrity.

Considering the first failure mode in light of Western's petition, an environment event, such as seismic or wind loads that exceed design, could result in tank failure and would be likely to result in failure inside impoundment of the transfer line as well, since by their design, transfer lines have equivalent or greater susceptability to failure from such events. Also, failure of a tank that results in its collapse (e.g., toe overload or tilt from other causes with subsequent spillage from the cryogenic shell causing embrittlement and fracture of the overstressed noncryogenic outer shell) will almost certainly rupture the transfer line inside impoundment. The point of penetration through the dike would be the most likely failure location because of the physical constraint and resulting stress. Thus, for safety considerations, it must be presumed that a tank failure would be accompanied by failure of the transfer line within the impounding system.

In the event of such failure, prevention of uncontrollable flow from impoundment would rely on the transfer line and valve located beyond the diking being unimpaired with the valve closed. Such reliance is not justified in view of the susceptability to damage of transfer lines when subjected to a tank-damaging environmental event. Also, even if loss of integrity of the external transfer system does not result from the environmental event, simultaneous thermal and mechanical shock from the sudden impact of LNG could cause the external cryogenic value, if initially at ambient temperature, to rupture. An incident of this type is reported to have occurred at the LNG plant in Arzew, Algeria, on March 30, 1977. As reported, an aluminum valve on the transfer line of an inground tank shattered when impacted by LNG without precooling. Spillage was estimated at 37,500 to 150,000 gallons, and superheat explosions from LNG contact with water continued for 12 hours. Windows 15km away were claimed to have been broken. One fatality at the plant resulted.

The second failure mode—loss of dike integrity—is of equal or greater concern. Where maximum stress levels are expected to be relatively high by design, logical engineering principles require a configuration that is regular and free of discontinuities in order to minimize uncertainties in stress analysis. The importance of this principle is recognized in the gas pipeline safety standards (49 CFR Part 192) where stress levels in pipelines must be reduced at locations near valve assemblies, fabricated assemblies, and certain fittings and connections, even though stresses are relatively controllable (e.g., fluid pressure is controlled by relief or other devices). It becomes more significant when the stress producing forces are not controllable, as the case would be in extreme environmental events coupled with loading from the collapsing transfer line and thermal contraction stress from impinging LNG, along with hydrodynamic action of the spilling fluid. Penetration by transfer lines in dikes would be subject to both uncertainties in stress analysis and indeterminate loading forces, and Western has offered no substantiation that the design standards it propose to apply to penetrations can be met. Even under normal operation, the point of penetration could be subject to frequent thermal cycling with the associated possibility of time-dependent deterioration of the dike's mechanical properties. Also, the seal structure for penetration could be subject to thermal shock and high thermal gradients from an LNG spill, with resulting mechanical distortions and seal failure.

The petition and partial supporting comment by FERC are primarily based on economic grounds. While MTB believes that added costs are likely, it is important to note that the Final Evaluation did not show § 193.2161 to be a high cost section requiring a detailed probability analysis of costs and benefits.

As to the alleged maintenance and handling difficulties, MTB believes that additional pumps should increase service life as well as reduce routine preventive maintenance.

Neither additional impounding capacity or increased exclusion distance would automatically follow from the penetration prohibition. Rather, it would be a design decision of the operator, since large capacity in-tank pumps; with high discharge pressure and complete systems for removal are currently available.

Considering the broad economic picture, most existing LNG plants have elected over-the-dike transfer. Even the petitioner has incorporated tank-top transfer in its plant planned for Point Conception, California, which would presumably include transfer over the dikes as a combined feature of safety and economics. Accordingly, the petition is denied.

§ 193.2165 Dike dimensions.

INGAA finds the phrase "inside edge of the top of the dike" confusing as it applies the second time in § 193.2165. However, the recommended change for clarity does not

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properly define the dimensions involved. We believe the term "liquid level impounded" may be the source of confusion, because it does not necessarily mean liquid level of the component served by impoundment as intended. MTB has revised the wording for clarity.

§ 193.2175 Shared impoundment.

AGA and INGAA argue that this rule could easily be interpreted to require each component inside an impounding system to be separately impounded, which would be impractical and unreasonable. The petitioners' suggested wording would require protection in accordance with § 193.2107, dealing with high and low temperature.

Section 193.2175 was intended as a more stringent requirement than § 193.2107. The original intent was that if items to be impounded as required by § 193.2149 are included within a single impounding system (shared impoundment), leakage from one item should not cause another to leak and possibly overwhelm the system. MTB now recognizes the unreasonableness in applying this policy to, say, a storage tank and its transfer line or other component combinations. As by far, the greatest hazard would be a leak from an LNG storage tank causing a leak in another storage tank. MTB believes protection can be reasonably provided in these cases and is revising the section to apply only to LNG storage tanks. Other components mentioned by INGAA, such as piping, valves, compressors, etc., would be covered by § 193.2107.

§ 193.2181(a) Impoundment capacity, LNG storage tanks.

AGA recommends that the required impoundment capacity for Class 2 and 3 impounding systems be changed from 150 percent to 110 percent, arguing that a 50 percent safety factor is unreasonable in light of the vapor dispersion zone required by § 193.2059 and the allowable use of vapor barriers under § 193.2163. Western recommends 100 percent for all classes of impoundment, plus any additional volume needed to meet the requirements of § 193.2151 and 193.2165, concerning dike design, and § 193.2179, impoundment capacity in general. Western argues that these sections will require varying degrees of capacity above 100 percent in amounts sufficient to keep a liquid impounded.

FERC argues that while it may be possible to design a dike to withstand phenomena such as wetting, splash, and wave action, the lack of acceptable hydrodynamic models justifies the 150 percent capacity.

As indicated by the FERC comment, dike designs which can assure containment of a spill from a major tank failure are unproven. In the case of low distant diking, configuration which can counteract horizontal components of motion in a rising wave of LNG impacting a dike face are only theoretical. Even with more testing, a question of scaling effects may remain, since large scale tests may not be practical.

With high close-in dikes, the question about formation and residence time of vapor bubbles from vaporization, with resulting expansion which could cause the column of LNG to overflow a dike, has not been fully resolved. Also, the rise in the impounded LNG column above the level of equilibration due to the kinetics of a rapid release (U-tube effect) could add to this problem.

Since designs that will reliably prevent overflow in the event of a major spill from an LNG storage tank have not yet been established, MTB believes that excess capacity is necessary to provide a factor of safety for Class 2 and 3 systems serving LNG storage tanks. Accordingly, MTB stands by its original position stated in the preamble of the NPRM and the final rules and leaves § 193.2181(a) unchanged.

Clarifying amendments. The scope of Part 193, as stated in § 193.2001, now exempts marine cargo transfer systems from any of the requirements in Part 193. Under the MTB/USCG memorandum of understanding (MOU) on the regulation of waterfront LNG facilities (published in the NPRM), the siting of these facilities, except with respect to vessel traffic management, is to be subject to MTB regulatory authority. Thus, as currently stated, the scope of Part 193 conflicts with the MOU regarding the siting of marine cargo transfer systems and associated facilities. Section 193.2001(b) (3) is, therefore, amended to make it clear that the Part 193 siting requirements apply to marine cargo transfer systems (not including those portions in navigable water excluded from jurisdiction under § 193.2001(o) (4)).

So that there is no doubt about which of the safety standards in Part 193 govern "siting," the title and scope of Subpart B are amended to refer to the Subpart B requirements as "siting requirements," rather than site-related design requirements. The "site-related design" term was used in the ANPRM and NPRM since the Act at that time did not specifically authorize regulations for siting LNG facilities. The siting provisions were proposed, therefore, as an aspect of facility design, which it is in a generic sense of design.

The current definition of "LNG facility" refers to pipeline facilities that are "used in the process of" activities related to producing, transferring, or storing LNG or changing LNG to gas. MTB believes the words "in the process of" restrict the meaning of "LNG facility" in a way not intended by the Act. To be more consistent with the Act's definition, the term "LNG facility" under § 193.2007 is amended by replacing the words "in the process of" with the word "for." This change more correctly classifies pipeline facilities as LNG facilities that are associated with the various LNG processes, even though they may not directly be a part of a particular process.

Recordkeeping. The effective date of the recordkeeping requirements of §§ 193.2119 and 193.2329 and other provisions incorporated by reference in Part 193 was postponed in the final rules document published at 45 FR 9184 pending

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coordination with the Office of Management and Budget under the Federal Reports Act. MTB has since determined that such coordination is not required by that Act and, consequently, an effective date for those recordkeeping requirements is established by this document as set forth above.

In view of the foregoing, 49 CFR Part 193 is amended as follows:

1. In § 193.2001, paragraph (b) (3) is revised to read as follows:

§ 193.2001 Scope of part.

• • • • •

(b) • • •

(3) In the case of a marine cargo transfer system and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last tank) located immediately before a storage tank.

• • • • •

2. In § 193.2005, paragraph (b) (1) is revised to read as follows:

§ 193.2005 Applicability.

• • • • •

(b) • • •

(1) The siting requirements apply only to LNG storage tanks that are significantly altered by increasing the original storage capacity or relocated, not pursuant to an application for approval filed as provided by paragraph (a) (2) of this section before March 1, 1978, and

• • • • •

3. In § 193.2007, the definition of "LNG facility" is amended to read as follows:

§ 193.2007 Definitions.

• • • • •

"LNG facility" means a pipeline facility that is used for liquefying or solidifying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas.

• • • • •

4. Section 193.2015 is revised to read as follows:

§ 193.2015 Petitions for finding or approval.

Where a rule in this part authorizes the Director to make a finding or approval, any operator may petition the Director to make such finding or approval. Petitions must be sent to the Director, Materials Transportation Bureau, 400 7th Street, SW., Washington, D.C. 20590, and be received at least 90 days before the operator requests that the finding or approval be made. Each petition must refer to the rule authorizing the action sought and contain information or arguments that justify the action. Unless otherwise specified, no public proceeding is held on a petition before it is granted or denied. Within 90 days after a petition is received, the Director notifies the petitioner of the disposition of the petition or, if the request requires more extensive consideration or additional information or comments are requested and delay is expected, of the date by which action will be taken.

5. Section 193.2051 is revised to read as follows:

§ 193.2051 Scope.

This subpart prescribes siting requirements for the following LNG facilities: Containers and their impounding systems, transfer systems and their impounding systems, emergency shutdown control systems, fire control systems, and associated foundations, support systems, and normal or auxiliary power facilities necessary to maintain safety.

• • • • •

6. In § 193.2057, paragraph (a) (1) is revised to read as follows, and item (6) of the table under paragraph (d) is amended by deleting the words "property line" and inserting the words "right-of-way" in lieu thereof:

§ 193.2057 Thermal radiation protection.

(a) • • •

(1) Within the thermal exclusion zone, the impounding system may not be located closer to targets listed in paragraph (d) of this section than the exclusion distance "d" determined according to this section, unless the target is a pipeline facility of the operator.

• • • • •

7. In § 193.2059, paragraph (d) (1) (i) is revised to read as follows:

§ 193.2059 Flammable vapor-gas dispersion protection.

• • • • •

(d) • • •

(1) • • •

(i) The rate of vaporization is not less than the sum of flash vaporization and vaporization from boiling by heat transfer from contact surfaces during the time necessary for spill detection, instrument response, and automatic shutdown by the emergency shutdown system but, not less than 10 minutes, plus, in the case of impounding systems for LNG storage tanks with side or bottom penetrations, the time necessary for the liquid level in the tank to reach the level of the penetration or equilibrate with the liquid impounded assuming failure of the internal shutoff valve.

• • • • •

8. In § 193.2061, paragraph (f) is revised, paragraph (g) is redesignated as (h), and a new paragraph (g) is added to read as follows:

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§ 193.2061 Seismic investigation and design forces.

• • • • •

(f) An LNG storage tank or its impounding system may not be located at a site where an investigation under paragraph (c) of this section shows that any of the following conditions exists unless the Director grants an approval for the site:

(1) The estimated design horizontal acceleration exceeds 0.8g at the tank or dike foundation.

(2) The specific local geologic and seismic data base is sufficient to predict future differential surface displacement beneath the tank and dike area, but displacement not exceeding 30 inches cannot be assured with a high level of confidence.

(3) The specific local geologic and seismic data base is not sufficient to predict future differential surface displacement beneath the tank and dike area, and the estimated cumulative displacement of a Quaternary fault within one mile of the tank foundation exceeds 60 inches.

(4) The potential for soil liquefaction cannot be accommodated by design and construction in accordance with paragraph (b) (1) of this section.

(g) An application for approval of a site under paragraph (f) of this section must provide at least the following:

(1) A detailed analysis and evaluation of the geologic and seismic characteristics of the site based on the geotechnical investigation performed under paragraph (c) of this section, with emphasis on prediction of near-field seismic response.

(2) The design plans and structural analysis for the tank, its impounding system, and related foundations, with a report demonstrating that the design requirements of this section are satisfied, including any test results or other documentation as appropriate.

(3) A description of safety-related features of the site or designs, in addition to those required by this part, if applicable, that would mitigate the potential effects of a catastrophic spill (e.g., remoteness or topographic features of the site, additional exclusion distances, or multiple barriers for containing or impounding LNG).

(h) • • •

9. In § 193.2067, paragraph (a) (3) and (b) (2) are revised to read as follows:

§ 193.2067 Wind forces.

(a) • • •

(3) In the case of impounding systems for LNG storage tanks, impact forces and potential penetrations by wind borne missiles.

(b) • • •

(2) For all other LNG facilities—

(i) An assumed sustained wind velocity of not less than 200 miles per hour, unless the Director finds a lower velocity is justified by adequate supportive data; or

(ii) The most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

§ 193.2109 (Amended)

10. In § 193.2109, paragraph (c) is amended by inserting the word "detrimental" between the words "to" and "ultraviolet."

11. In § 193.2123, paragraph (d) is revised to read as follows:

§ 193.2123 Valves.

• • • • •

(d) Powered local and remote operation must be provided for valves intended for use during a controllable emergency that would be difficult or excessively time-consuming to operate manually during such an emergency.

• • • • •

§ 193.2165 (Amended)

12. Section 193.2165 is amended by inserting the word "horizontal" between the words "the" and "distance" and by deleting the word "impounded" and inserting the words "in the component or vessel" in lieu thereof.

13. Section 193.2175 is revised to read as follows:

§ 193.2175 Shared impoundment.

When an impounding system serves more than one LNG storage tank, a means must be provided to prevent low temperature or fire resulting from leakage from any one of the storage tanks served causing any other storage tank to leak. The means must not result in a vapor dispersion distance which exceeds the exclusion zone required by § 193.2059.

Subpart B [Title Amended]

14. In the table of sections and the text of the rules, the title of Subpart B is amended by deleting "Site Related Design Requirements" and inserting "Siting Requirements" in lieu thereof.

(49 U.S.C. 1674a; 49 CFR 1.53 and Appendix A of Part 1)

Issued in Washington, D.C., on August 21, 1980.

L. D. Santman,

Director, Materials Transportation Bureau

[FR Doc. 80-26213 Filed 8-17-80; 8:45 am]

Billing Code 4910-80-M

DEPARTMENT OF TRANSPORTATION
Materials Transportation Bureau
Research and Special Programs Administration, Transportation Department
49 CFR Part 192
(Amdt. 192-27B, Docket OPS-30)
Transportation of Natural and Other Gas by Pipeline; Repair of Transmission Lines

AGENCY: Materials Transportation Bureau, DOT.

ACTION: Final rule.

SUMMARY: This document amends Material Transportation Bureau's regulation on general requirements for repair procedures of gas pipelines (49 CFR 192.711) by correcting a reference to another section which has been redesignated.

EFFECTIVE DATE: This amendment becomes effective January 17, 1980.

FOR FURTHER INFORMATION CONTACT:

Ralph T. Simmons (202) 426-2394.

SUPPLEMENTARY INFORMATION: Section 192.711(b) refers to § 192.717(c). This referenced section was redesignated as § 192.717(a) (3) in Amendment 192-27 (41 FR 34598), but the reference in § 192.711(b) was not changed accordingly.

Since this amendment is an editorial change and does not make a substantive change to the regulations, public participation in this rulemaking is unnecessary.

In consideration of the foregoing § 192.711(b) is amended by deleting the reference to "§ 192.717(c)" and inserting in lieu thereof "§ 192.717(a) (3)."

(49 U.S.C. 1672; U.S.C. 1804, 49 CFR 1.53, Appendix A of Part 1 and Appendix A of Part 106.)

Issued in Washington, D.C., on January 9, 1980.

L. D. Santman,
Director, Materials Transportation Bureau

(FR Doc. 80-1460 Filed 1-18-80; 8:45 am)
Billing Code 4910-60-80

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APPENDIX B

Amendments to 49 CFR Part 195

1. Transportation of Liquids by Pipelines; Addition of Water to Pipelines Transporting Anhydrous Ammonia.
2. Hydrostatic Testing of Liquid Pipelines.
3. Testing Highly Volatile Liquid Pipelines.
4. Seams on Adjacent Pipe Lengths.

49 CFR Part 196
(Amdt. 196-20, Docket No. PS-56A)
Transportation of Liquids by Pipeline; Addition of Water to Pipelines Transporting Anhydrous Ammonia

AGENCY: Materials Transportation Bureau (MTB), DOT.

ACTION: Final rule.

SUMMARY: This final rule prescribes periodic monitoring of the water content of pipelines transporting anhydrous ammonia and the addition of water to such pipelines if the water content is less than 0.2 percent by weight. The purpose of this final rule is to reduce the potential for stress corrosion cracking.

EFFECTIVE DATE: The effective date of the final rule is February 2, 1981 for hazardous liquid pipelines currently subject to Part 195. Upon reissuance of Part 195 under the authority of the Hazardous Liquid Pipeline Safety Act of 1979 (Title II of Pub. L. 96-129, November 30, 1979) and in accordance with the notice of proposed rulemaking (NPRM) in this docket, the effective date of this final rule for intrastate liquid pipelines not now subject to Part 195 will be announced.

FOR FURTHER INFORMATION CONTACT:

Frank S. Robinson (202) 426-2392.

SUPPLEMENTARY INFORMATION: An advance notice of proposed rulemaking (Docket PS-56, Notice 1, 44 FR 6961, February 5, 1979) solicited comments on the need to amend Part 195 to require the use of water as an inhibitor in ammonia pipelines. As a result of the information gained from the publication of the advance notice, MTB issued an NPRM on February 7, 1980 (45 FR 8323), proposing to amend Section 195.418, "Internal Corrosion Control," by adding a paragraph to require monitoring of the water content of pipelines transporting anhydrous ammonia and the addition of water to such pipelines if the water content is less than 0.2 percent by weight. The purpose of the proposed rule was to reduce the potential for stress corrosion cracking.

The American Petroleum Institute (API), the American Society of Mechanical Engineers B31.4 Code Section Committee for Liquid Petroleum Transportation Piping Systems, and one major carrier of anhydrous ammonia responded to the notice.

The API stated that (1) it is not aware of any stress corrosion cracking problems peculiar to pipelines which transport anhydrous ammonia; (2) the MTB should publish a cost/benefit evaluation of the proposed rule; (3) the rule should be written in performance language which allows the affected carriers flexibility to achieve the regulatory goal; and (4) the proposed rule is redundant in view of the regulatory requirements of § 195.6 and the fact that carriers have been required as a condition of operation under that rule to maintain 0.2 percent water in the anhydrous ammonia they transport. MTB recognizes all of these issues, but believes that they were addressed adequately in the NPRM in justification of the proposal. Since there has been no additional information submitted, there is no need for further assessment or evaluation of the issues in this document.

The major carrier recognized the need to add water to anhydrous ammonia pipelines. It argued against the proposal, however, on the basis that (1) § 195.418 adequately addresses the requirement in a general manner, and (2) means to inhibit stress corrosion cracking other than the addition of water might be developed in the future. The MTB does not agree that § 195.418 adequately covers the problem of stress corrosion cracking in ammonia pipelines. Section 195.418 is written in very general terms, and does not reflect the singular remedy available to combat stress corrosion cracking. Although this rulemaking does not foreclose the opportunity for future rule changes if other means are developed in the future to deal with the problem, MTB believes the stress corrosion is of such significance that the Part 195 regulations must reflect the only known remedy available, the addition of water.

The B31.4 Code Section Committee supported the proposed rule for the reasons set forth in the notice, and advised that the 1979 edition of the B31.4 Code issued February 28, 1980, incorporated the same requirements for the addition of water to anhydrous ammonia pipelines as those proposed in the notice.

In view of (1) the information in Docket HM-213 indicating that stress corrosion cracking in facilities handling anhydrous ammonia can be inhibited with the addition of water, (2) the recognition by most of the commenters to the advance notice and the NPRM that the addition of water will combat stress corrosion cracking and the fact that no other remedy is available for the purpose, and (3) the use of this means as demonstrated by the incorporation into the B31.4 Code of requirements to add water to pipelines

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transporting anhydrous ammonia, 49 CFR Part 195 is amended by adding a new § 195.418(e) as follows:

§ 195.418 Internal corrosion control.

* * * * *

(e) Anhydrous ammonia must contain at least 0.2 percent water by weight. Each carrier of anhydrous ammonia must monitor the water content of each pipeline weekly, but with intervals of not more than 10 days. Also, the monitoring must be performed for each source of supply for the pipeline.

(49USC 2002; 49 CFR 1.53(a), and Appendix A to Part 1)

Issued in Washington, D.C., on December 19, 1980.

L. D. Santman,

Director, Materials Transportation Bureau

[FR Doc. 80-40628 Filed 12-31-80; 8:45 am)

Billing Code 40 10-80-M

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49 CFR Part 195
(Amdt. 195-18, Docket PS-63
Transportation of Liquids by Pipeline; Hydrostatic Testing

AGENCY: Materials Transportation Bureau (MTB).

ACTION: Final rule.

SUMMARY: This final rule reduces the time and cost of hydrostatic testing in light of studies which show that the currently required 24-hour hydrostatic hold period is unnecessary. A two part test is prescribed for hydrostatically testing liquid pipelines. A strength test of at least 4 hours' duration at a pressure equal to 125 percent or more of the maximum operating pressure is prescribed for all hazardous liquid pipelines subject to Part 195; additionally, a leak test for four hours or more at a pressure equal to 110 percent or more of the maximum operating pressure is prescribed for those pipelines which are not visually inspected for leakage while under the strength test.

DATE: Because this final rule relaxed an existing requirement, resulting in substantial cost savings, the effective date of the final rule is September 8, 1980, for hazardous liquid pipelines currently subject to Part 195. Upon reissuance of Part 195 under the authority of the Hazardous Liquid Pipeline Safety Act of 1979 (Title II of Pub. L. 96-129, November 30, 1979) and in accordance with the notice of proposed rulemaking in this docket, the effective date of this final rule for intrastate liquid pipelines not now subject to Part 195 will be announced.

FOR FURTHER INFORMATION CONTACT:

Frank Robinson (202) 426-2392.

SUPPLEMENTARY INFORMATION: A notice of proposed rulemaking (NPRM) was published March 13, 1980 (45 FR 16230), proposing to reduce the 24-hour hydrostatic hold period in § 195.302(c) for all hazardous liquid pipelines. (After publication of the NPRM, § 195.302(b) was renumbered § 195.302(c).) Section 195.302(c) requires that hydrostatic tests be maintained for at least 24 hours without leakage. The MTB believed this requirement was more than adequate to ensure pipeline safety and resulted in greater testing costs than were necessary.

The purpose of a hydrostatic test is to ensure that a pipeline will not later fail in service due to latent material or construction defects. Broadly defined, the hydrostatic test is the maintenance of water pressure above the maximum operating pressure (MOP) under no-flow conditions for a fixed period of time. The hydrostatic test precludes later rupture or leak due to latent material or construction defects by causing these potentially harmful defects to surface during the test period.

The 24-hour hold period for hydrostatic testing evolved as an industry safety practice before it could be explained why failures occurred during the hold period. Further, there was no distinction made between testing the pipeline for strength and testing the pipeline for leakage.

In recent years, scientific research and industry experience have demonstrated that the 24-hour hold period is not necessary to ensure pipeline integrity and that a distinction can be made between a strength test and a leak test. Some of that research and experience was discussed in the NPRM.

Response to the Notice and Development of Final Rule

Nine oil and gas companies, the American Petroleum Institute (API), the Chemical Manufacturers Association (CMA), the Interstate Natural Gas Association of America (INGAA), the Offshore Operators Committee (OOC), the B31.4 Code Section Committee for Liquid Petroleum Transportation of the American Society of Mechanical Engineers, and the National Transportation Safety Board (NTSB), commented on the NPRM. None of the commenters argued that the proposed rule to reduce the hydrostatic test period was not adequate to ensure pipeline safety and most commenters agreed that reduced costs of testing would result.

The INGAA, the OOC, and three oil and gas companies recommended modifying the language of the proposed rule so that prescribed test pressures and hold periods would be clearly stated as minimum requirements in order to avoid the possibility of the rules being interpreted as maximum permissible standards. Further, although these commenters agreed that the rules as proposed are adequate to ensure safety, they argued that there can be other reasons for testing to higher pressures or maintaining longer hold periods than those prescribed in the proposed rule. For example, thermal effects on the test water and pipe being tested can require a hold period longer than 4 hours to be certain that pressure has stabilized. Additionally, as a practical matter, it may be necessary to raise the pressure to a point above the test level to be certain that the desired test

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pressure has been achieved throughout the length of pipeline under test.

Although the proposed rule was intended to establish minimum testing standards, the MTB agrees with the commenters that there is a need to more clearly state the rule to avoid ambiguity. The MTB further agrees with the commenters that there can be cases wherein it may be advisable to exceed the prescribed pressures and hold periods while conducting the testing, and the rule should provide for these cases. As a result, the qualifying phrases "at least" and "or more" have been added to § 195.302(c) in the final rule with reference to the prescribed test pressures and hold periods.

The OOC recommended that offshore pipelines be tested to 125 percent of MOP for two hours instead of the proposed four hour strength test at 125 percent of MOP, and the four hour leak test at 110 percent of MOP where not visually inspected for leakage during the strength test. The OOC argued that the research report cited in the notice "Background Behind Proposed Test Pressure Hold Period of 2 Hours" by G. M. McClure provides ample justification for the two hour hold period. The MTB is not prepared at this time to further reduce the testing requirements for offshore pipelines below the levels proposed, because: (1) the reduction in the test hold period proposed in the notice is consistent with the cited research as well as industry experience reflected in the B31.4 code and the API petition (P3); (2) the proposed reduction in the test hold period will provide most of the economic advantages of short period testing; and (3) four hours, or perhaps more, is required to discover leaks that may be present.

The NTSB recommended that criteria for the test procedure and monitoring equipment be prescribed, arguing that improved procedures and monitoring equipment will be required to assure compliance with the regulations. No evidence has been presented to show that a shorter test period will require substantially different procedures or equipment than a test of longer duration, and even where differences exist, MTB feels confident that the records required by § 195.310 will continue to assure that a proper test has been conducted. Consequently, no further regulations concerning test procedures or test equipment have been included in the final rule.

Several of the commenters commended the MTB for revising the pipeline safety regulations as technology for testing develops and for taking positive steps to reduce the cost of testing. The MTB estimates that testing costs will be reduced by 30 percent resulting in a $12,000,000 annual savings to the industry.

In view of the foregoing, the MTB amends 49 CFR Part 195 by revising § 195.302(c) to read as follows:

§ 195.302 General requirements.

* * * * *

(c) The test pressure for each hydrostatic test conducted under this section must be maintained throughout the part of the system being tested for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure and, in the case of a pipeline that is not visually inspected for leakage during test, for at least an additional 4 continuous hours at a pressure equal to 110 percent, or more, of the maximum operating pressure.

The MTB has determined that this document does not contain a major proposal requiring preparation of a regulatory analysis under DOT procedures. Also, because of the estimated cost savings, a full Final Evaluation is not needed.

(Hazardous Liquid Pipeline Safety Act of 1979 (Title II of Pub. L. 96-129, November 30, 1979, 93 Stat. 1003); 49 CFR 1.53(a), Appendix A to Part 1)

Issued in Washington, D.C., on September 3, 1980.

L. D. Santman,

Director, Materials Transportation Bureau

[FR Doc. 80-27479 Filed 9-8-80; 8:45 am)

Billing Code 40 10-80-M

Research and Special Programs Administration
49 CFR Part 195
(Amdt. 195-19, Docket No. OPSO-48
Seams on Adjacent Pipe Lengths

AGENCY: Materials Transportation Bureau (MTB).

ACTION: Final rule.

SUMMARY: This final rule revokes § 195.218 which requires that seams on adjacent pipe lengths be offset. This action is taken because the pipe manufacture and weiding technology has advanced sufficiently to make the requirement of this section unnecessary.

EFFECTIVE DATE: September 8, 1980.

FOR FURTHER INFORMATION CONTACT:

Frank Robinson (202) 426-2392.

SUPPLEMENTARY INFORMATION: On September 21, 1977, MTB issued a notice of proposed rulemaking (Notice 77-6, 42 FR 48900) proposing to revoke § 195.218, "Welding Seam Offset." The notice invited comments from interested persons concerning the need to offset weld seams on adjacent pipe lengths as required by § 195.218. MTB initiated this rulemaking proceeding as a result of waivers granted to the Alyeska Pipeline Service Company. Information provided in support of the waivers demonstrated that technological advances in pipe manufacture and welding have minimized the likelihood of weld failure due to residual stresses and have, therefore, made unnecessary the requirement to offset adjacent longitudinal weld seams.

Seven commenters responded to the notice. Six industry commenters, including the American Petroleum Institute and the American National Standards Committee B-31, concurred with MTB's proposed revocation of the offset requirement of § 195.218 for the same reasons given in the notice.

One dissenting industry commenter argued that removal of § 195.218 is not warranted in all cases because much of the pipe that could be installed may not have been manufactured according to the latest technology. This commenter stated that the Alyeska pipeline was built to a specification which included requirements for ductility and notch toughness of weld and pipe metals in the arctic environment. However, Notice 77-6 was not issued on the basis that lin pipe available for use in liquid service throughout the U.S would have material characteristics similar to those on th Alaskan pipeline. Rather, the notice was predicated on th fact that pipe manufacturing and welding technology ha advanced in the area of ductility to the point wher § 195.218 is no longer necessary. This statement is as tru for Grade B pipe, made to standard API 5L, as it is for th higher strengths and grades of pipe. Each of the normall followed API standards for pipe manufacture API 5L an 5LX, provides for a level of ductility that is high enough t remove the potential under normal operating conditions o weld seam failure and propagation that § 195.218 wa intended to prevent. Although Grade B pipe may be mor brittle under cold conditions than the higher grades of pipe due to its higher transition temperature from a ductile t brittle condition, § 195.102 requires the carrier to selec component material for the temperature environment i which the component will be used to assure that structura integrity is not impaired. For these reasons, the MTI believes it is not necessary to maintain the requirement t offset weld seams on Grade 5 pipe or other pipe.

In view of the cost savings that will result from the revoca tion of this regulation the effective date of this final ruie i September 8, 1980.

In consideration of the foregoing, 49 CFR Part 195 i amended as follows:

§ 195.218 [Revoked]

1. By revoking § 195.218 "Welds: Seams Offset."

2. By deleting § 195.218 from the table of section (Hazardous Liquid Pipeline Safety Act of 1979 (Title II o Pub. L. 96-219, November 30 1979); 49 CFR 1.53 and Ap pendix A of Part 1).

Issued in Washington, D.C., on September 2, 1980.

L. D. Santman,

Director, Materials Transportation Bureau

[FR Doc. 80-27220 Filed 9-8-80; 8:45 am)

Billing Code 40 10-80-M

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APPENDIX C

GAS PIPELINE SAFETY ENFORCEMENT ACTIVITY

1. Enforcement Cases Initiated
2. Warning Letters Issued
3. Compliance Orders Issued
4. Civil Penalty Assessments
5. Enforcement Cases Closed Without Penalty
6. Enforcement Cases Closed With Warning Letter
7. Enforcement Cases Resolved by the Collection of a Civil Penalty

ENFORCEMENT CASES INITIATED

Eastern Region	
Timberlane Mobile Home Park (Reybold Home, Inc.)	Newark, DE
Charlottesville, VA	Charlottesville, VA
National Fuel Gas Supply Corp.	Hamburg, NY
Olde Towne Village Condominium	District Heights, MD
Colonial Pipeline Co.	Atlanta, GA
North Penn Gas Co.	Port Allegheny, PA
Georgetown Service and Gas Co.	Georgetown, DE
Marcus Garvey Village (Duber Associates, New York, NY)	Brooklyn, NY
Southern Region	
North Middletown, KY	North Middletown, KY
Waynesboro, GA	Waynesboro, GA
Cordele, GA	Cordele, GA
Talbotton, GA	Talbotton, GA
Woodland, GA	Woodland, GA
Henderson, KY	Henderson, KY
Wheelwright, KY	Wheelwright, KY
Olive Hill, KY	Olive Hill, KY
Thomasville, GA	Thomasville, GA
Pelham, GA	Pelham, GA
Drakesboro, KY	Drakesboro, KY
Meigs, GA	Meigs, GA
Carlisle, KY	Carlisle, KY
Adairsville, GA	Adairsville, GA
Morganfield, KY	Morganfield, KY
Fulton, KY	Fulton, KY
Moultrie, GA	Moultrie, GA
Toccoa, GA	Toccoa, GA
Union Point, GA	Union Point, GA
Buford, GA	Buford, GA
Winder, GA	Winder, GA
Central Region	
Texas Eastern Gas Pipeline Co.	Houston, TX
Associated Natural Gas Co.	Blytheville, AR
Louisburg Trailer Park	Louisburg, KS
Southwest Region	
Port Barre, LA	Port Barre, LA
Ville Platte, LA	Ville Platte, LA
Kaplan, LA	Kaplan, LA
St. James Parish Police Jury	Convent, LA
Sicily Island, LA	Sicily Island, LA
Walker, LA	Walker, LA
Thibodaux, LA	Thibodaux, LA
Madisonville, LA	Madisonville, LA
Scott, LA	Scott, LA
Jena, LA	Jena, LA
Louisiana-Nevada Transit Co.	Denver, CO
Alexandria, LA	Alexandria, LA
Breaux Bridge, LA	Breaux Bridge, LA
Chatham, LA	Chatham, LA
Livonia, LA	Livonia, LA
Grand Coteau, LA	Grand Coteau, LA
Western Region	
Shadow Mountain Village Mobile Home Park (Tower Management Co., Pasadena, CA)	Las Vegas, NV

WARNING LETTERS ISSUED

Eastern Region	
Munhall Homesteads Housing Association	Munhall, PA
Consolidated Gas Supply Corp.	Clarksburg, WV
Southern Region	
Panhandle Eastern Pipeline Co.	Kansas City, MO
Monroe, GA	Monroe, GA
Wrens, GA	Wrens, GA
Unadilla, GA	Unadilla, GA
Warner Robins, GA	Warner Robins, GA
Dublin, GA	Dublin, GA
Florida Gas Transmission Co.	Winter Park, FL
Sylvania, GA	Sylvania, GA
Commonwealth Service Corp.	Wickliffe, KY
Claxton, GA	Claxton, GA
Kentucky West Virginia Gas Co.	Ashland, KY
Summerville, GA	Summerville, GA
Trion, GA	Trion, GA
Michigan Wisconsin Pipeline Co.	Detroit, MI

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Central Region

Michigan Wisconsin Pipeline Co.	Detroit, MI
Cities Service Gas Co.	Oklahoma City, OK
Panhandle Eastern Pipeline Co.	Kansas City, MO
Michigan Gas Storage Co.	Jackson, MI
American Natural Resources Co.	Detroit, MI
Great Plains Natural Gas Co.	Fergus Falls, MN

Southwest Region

Gas Utility District #1 West Feliciana Parish	St. Francisville, LA
Patterson, LA	Patterson, LA
Gueydon, LA	Gueydon, LA
Boyce, LA	Boyce, LA
Krotz Springs, LA	Krotz Springs, LA
Montgomery, LA	Montgomery, LA
Ville Platte, LA	Ville Platte, LA
Columbia, LA	Columbia, LA
Montpelier, LA	Montpelier, LA
Washington, LA	Washington, LA
Basile, LA	Basile, LA
Jena, LA	Jena, LA
Alexandria, LA	Alexandria, LA
St. John the Baptist Parish Police Jury	Garyville, LA
New Roads, LA	New Roads, LA
Arnaudville, LA	Arnaudville, LA
Scott, LA	Scott, LA

Western Region

Meadows Mobile Home Park (Hawaii Property, Inc., Dallas, TX)	Las Vegas, NV
Russian River Gas Co.	Gurnerville, CA
Lake Jennings Mobile Home Club	Lakeside, CA
Pepper Villa Mobile Estates	El Cahon, CA
Terrace View Mobile Estates	El Cahon, CA
Shadow Mountain Village Mobile Home Park (Tower Management Co., Pasadena, CA)	Las Vegas, NV
Alaska Gas and Service Co.	Anchorage, AK
Alaska Pipeline Co.	Anchorage, AK

COMPLIANCE ORDERS ISSUED

Eastern Region

Georgetown Service and Gas	Georgetown, DE

Southern Region

North Middletown, KY	Drakesboro, KY
Waynesboro, GA	Meigs, GA
Talbotton, GA	Carlisle, KY
Woodland, GA	Adairsville, GA
Henderson, GA	Fulton, KY
Wheelwright, GA	
Olive Hill, KY	
Thomasville, GA	
Pelham, GA	

Southwest Region

Ville Platte, LA	
Kaplan, LA	
St. James Parish Police Jury	Convent, LA
Walker, LA	
Thibodaux, LA	
Jena, LA	

ENFORCEMENT CASES CLOSED WITHOUT PENALTY

Eastern Region

Georgetown Service and Gas Co.	Georgetown, DE
Charlottesville, VA	Charlottesville, VA
Boston Gas Co.	Boston, MA
Equitable Gas Co.	Clarksburg, WV
Georgetown Service and Gas Co.	Georgetown, DE
Polinger Co.	Chevy Chase, MD
Orange and Rockland Utilities	Pearl River, NY
Vermont Gas Systems, Inc.	Burlington, VT
Charlottesville, VA	Charlottesville, VA

Southern Region

Cochran, GA	Cochran, GA
Tompkinsville, KY	Tompkinsville, KY
Montezuma, GA	Montezuma, GA
Bainbridge, GA	Bainbridge, GA
Sugar Hill, GA	Sugar Hill, GA
Southern Natural Gas Co.	Birmingham, AL
Columbia Gas Transmission Corp.	Charleston, WV

Central Region

Granby, MO	Granby, MO
Commercial Pipeline Co., Inc.	Wichita, KS
Nebraska Natural Gas Co.	Fremont, NE
Perryville, MO	Perryville, MO
New Haven, MO	New Haven, MO
Hermann, MO	Hermann, MO
Cities Service Gas Co.	Oklahoma City, OK

Southwest Region

Kaplan, LA	Kaplan, LA
Golden Meadow, LA	Golden Meadow, LA
Waterproof, LA	Waterproof, LA
St. Joseph, LA	St. Joseph, LA
Roseland, LA	Roseland, LA
Zachary, LA	Zachary, LA
Abita Springs, LA	Abita Springs, LA
Gonzalez, LA	Gonzalez, LA
Sicily Island, LA	Sicily Island, LA

Western Region

Barrow Utilities	Barrow, AK
Pacific Gas Transmission Co.	San Francisco, CA
Three Crowns Mobile Home Park (Carlsberg Management Co., Los Angeles, CA)	Las Vegas, NV
Carefree Country Mobile Home Park (Carlsberg Management Co., Los Angeles, CA)	Las Vegas, NV
Marathon Oil Co.	Anchorage, AK
Phillips Petroleum Co.	Bartlesville, OK
Union Oil Company of California	Ventura, CA
Tropicana East Mobile Home Park (Carlsberg Management Co., Los Angeles, CA)	Las Vegas, NV
Shadow Mountain Village Mobile Home Park (Tower Management Co., Pasadena, CA)	Las Vegas, NV

ENFORCEMENT CASES CLOSED WITH WARNING LETTER

Eastern Region

Olde Towne Village Condominium	District Heights, MD

Southern Region

Summerville, GA	Summerville, GA
Hazel, KY	Hazel, KY
Morganfield, KY	Morganfield, KY

Central Region

Albany, MO	Albany, MO
Grant City, MO	Grant City, MO

Southwest Region

Decambre, LA	Decambre, LA
Breaux Bridge, LA	Breaux Bridge, LA
Scott, LA	Scott, LA
Grand Coteau, LA	Grand Coteau, LA
Mamou, LA	Mamou, LA
Simmesport, LA	Simmesport, LA
Port Allen, LA	Port Allen, LA
St. James Parish Police Jury	Convent, LA
St. John the Baptist Parish Police Jury	Edgard, LA
Ville Platte, LA	Ville Platte, LA
Chatham, LA	Chatham, LA
Denham Springs, LA	Denham Springs, LA
Vidalia, LA	Vidalia, LA
Jena, LA	Jena, LA
Jackson, LA	Jackson, LA
Clinton, LA	Clinton, LA
Alexandria, LA	Alexandria, LA
Madisonville, LA	Madisonville, LA
Eunice, LA	Eunice, LA
Thibodeaux, LA	Thibodeaux, LA
West Baton Rouge Parish	Port Allen, LA
Gas Utility District #1, Livingston Parish Series B	Holden, LA

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Gas Utility District #2, Washington Parish	Franklinton, LA
Gas Utility District #3, Grant Parish	Colfax, LA
Gas Utility District #4, Grant Parish	Montgomery, LA
Gas Utility District #5, Grant Parish	Georgetown, LA
Gas Utility District #1, Winn Parish	Dodson, LA
Pointe Coupee Parish Police Jury	New Roads, LA
Madisonville, LA	Madisonville, LA
Livonia, LA	Livonia, LA

ENFORCEMENT CASES RESOLVED BY THE COLLECTION OF A CIVIL PENALTY

Eastern Region

Greentree Associates (Artery Organization, Inc., Chevy, Chase, MD)	Glen Burnie, MD
Lazy Hollow Apartment Complex (Artery Organization, Inc., Chevy Chase, MD)	Columbia, MD
Baltimore Gas and Electric Co.	Baltimore, MD
Consolidated Gas Supply Corp.	Clarksburg, WV

Southern Region

Scottsville, KY	Scottsville, KY
Richland, GA	Richland, GA
Tallapoosa, GA	Tallapoosa, GA
Tompkinsville, KY	Tompkinsville, KY
Scottsville, KY	Scottsville, KY
Pikeville, KY	Pikeville, KY
Flemingsburg, KY	Flemingsburg, KY
Cordele, GA	Cordele, GA
Henderson, KY (Partial resolution: case still open)	Henderson, KY

Central Region

Bernie, MO	Bernie, MO
Arkansas-Louisiana Gas Co.	Wichita, KS
New Florence, MO	New Florence, MO
Northern Natural Gas Co.	Omaha, NE
Springfield, MO	Springfield, MO
Commercial Pipeline Co., Inc.	Wichita, KS
Shelbina, MO	Shelbina, MO
Bismarck, MO	Bismarck, MO

Southwest Region

Arkansas-Louisiana Gas Co.	Shreveport, LA
Berwick, LA	Berwick, LA
Lone Star Gas Co.	Dallas, TX
Central Louisiana Electric Co.	Alexandria, LA

Western Region

Atlantic Richfield Co., North American Products Division	Bakersfield, CA
Casitas Pipeline Co. (Atlantic Richfield Co.)	Bakerfield, CA
Cuyama Pipeline Co. (Atlantic Richfield Co.)	Bakersfield, CA
Cheviot Hills Pipeline Co. (Atlantic Richfield Co.)	Bakersfield, CA
Cuyama Pipeline Co. (Atlantic Richfield Co.)	Bakersfield, CA
Palo Alto, CA	Palo Alto, CA
Long Beach, CA	Long Beach, Ca
Terra Resources, Inc.	Casper, WY
Shell Oil Co.	Los Angeles, CA
Shell Oil Co.	Los Angeles, CA

TOTAL AMOUNT COLLECTED—$55,300

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APPENDIX D

LIQUID PIPELINE SAFETY ENFORCEMENT ACTIVITY

1. Enforcement Cases Initiated
2. Warning Letters Issued
3. Civil Penalty Assessments
4. Enforcement Cases Closed Without Penalty
5. Enforcement Cases Closed With Warning Letter
6. Enforcement Cases Resolved by the Collection of a Civil Penalty

* U.S. GOVERNMENT PRINTING OFFICE: 1982--361-428/2052

ENFORCEMENT CASES INITIATED

Eastern Region

Getty Pipeline Co.	Tulsa, OK

Southwest Region

Cosden Oil and Chemical Co.	Big Spring, TX
Wickers Petroleum Corp.	Wichita, KS
Cities Service Pipe Line Co.	Tulsa, OK

Western Region

Wyco Pipeline Co. Standard Oil Co. (Indiana), Chicago, IL	Denver, CO

WARNING LETTERS ISSUED

Southern Region

Plantation Pipe Line Co.	Atlanta, GA

Central Region

Continental Pipe Line Co.	Houston, TX
Marathon Pipe Line Co.	Martinsville, IL
Gulf Central Pipe Line Co.	Tulsa, OK
Phillips Petroleum Co.	Bartlesville, OK
Minnesota Pipe Line Co.	Cottage Grove, MN
Texaco-Cities Service Pipeline Co.	Houston, TX
Willians Pipe Line Co.	Tulsa, OK
Lakehead Pipe Line Co.	Superior, WI
Shell Pipe Line Corp.	Indianapolis, IN
Ashland Pipe Line Co.	Lexington, OH
Wood River Pipeline Co.	Hazelwood, MO
ARCO Pipe Line Co.	Independence, KS

Southwest Region

Standard Transpipe Corp.	Cushing, OK
Koch Oil Co.	Wichita, KS

Western Region

Alaska Pipeline Service Co.	Anchorage, AK

CIVIL PENALTY ASSESSMENTS

Southwest Region

Cosden Oil and Chemical Co.	Big Spring, TX

ENFORCEMENT ACTIONS CLOSED WITHOUT PENALTY

Southwest Region

WESCO Pipe Line Co.	Denver, CO
River Pipeline Co. (Cosden Oil and Chemical Co., Big Spring, TX)	Big Spring, TX
Ashland Pipe Line Co.	Ashland, KY

Western Region

Husky Oil Co.	Cody, WY
Wyco Pipe Line Co. (Standard Oil Co. (Indiana), Chicago, IL)	Denver, CO

ENFORCEMENT CASES CLOSED WITH WARNING LETTER

Southwest Region

Vickers Petroleum Corp.	Wichita, KS
Okie Pipe Line Co.	Wichita, KS

Western Region

Alyeska Pipeline Service Co.	Anchorage, AK

ENFORCEMENT CASE RESOLVED BY THE COLLECTION OF A CIVIL PENALTY

Southwest Region

Cosden Oil and Chemical Co.	Big Spring, TX

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